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January 24, 2007

VIA HAND DELIVERY

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Blanca S. Bayo, Director
Division of Commission Clerk and
Administrative Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0800

Re: Docket No. 060635-EU

Dear Ms. Bayo:

Attached please find the original and ten copies of the Post Hearing Statement and Brief of Natural Resources Defense Council to be filed in the above styled docket.

Should you have questions or need any additional information, please contact me.

Very truly yours,

Suzanne Brownless
Attorney for NRDC

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION ORIGINAL

IN RE: Petition for Determination of Need for electrical power plant in Taylor County by Florida Municipal Power Agency, JEA, Reedy Creek Improvement District, and the City of Tallahassee.

DOCKET NO. 060635-EU
FILED: January 24, 2007

**POST HEARING STATEMENT AND BRIEF OF NATURAL RESOURCES DEFENSE COUNCIL**

Pursuant to ruling of the Chairman Edgar, the Natural Resources Defense Council (NRDC) files its Post Hearing Statement and Brief in the above-styled case and states as follows:

**BASIC POSITION**

The Applicants have failed to prove that the proposed 785 MW super critical pulverized coal plant to be located at the Taylor Energy Center (TEC) in Taylor County, Florida is the least cost alternative to meet their identified need for several reasons. First, the Applicants use of the FIRE model rather than the $/MWhr methodology used by the City of Tallahassee did not properly evaluate the cost-effectiveness of demand side management programs that could have reduced or postponed the need for TEC. Second, both the Reedy Creek Improvement District (RCID) and the Florida Municipal Power Agency (FMPA) did not verify the demand side management programs actually being used, or rejected, by their customers but simply relied upon the customers' representations that all cost-effective demand side management programs were already being implemented. Because neither FMPA nor RCID know exactly which programs are being implemented by their customers, the FIRE model sensitivity analyses conducted for these entities are invalid. Third, $CO_2$ emission costs should have been modeled to develop the base case IRP which included TEC. These $CO_2$ costs should have been developed using the more reasonable Synapse Energy Economics high forecast or the Hill & Associates McCain-Liberman multiclient CO2 emission analysis. At a minimum, the CO2 sensitivity study IRP should have used these more reasonable forecasts of CO2 emission prices. The base case IRP for TEC which ignores the imminent regulation of CO2 is totally without merit and should not be relied upon by the Commission to establish TEC as the least cost alternative to meet the Applicants' needs.

## ISSUES AND POSITIONS

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

**POSITION:** **The Applicants have not demonstrated that TEC is needed or appropriate takingn 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.**

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The Taylor Energy Center (TEC) need determination application considers the consolidated need for capacity and energy for four separate utilities: Florida Municipal Power Association (FMPA), JEA, Reedy Creek Improvement District (RCID) and the City of Tallahassee (COT). For each of the §403.519, F.S., "statutory issues" (Issues 1-4, 9 and 10), the Commission must evaluate each participant in TEC both separately and collectively and make utility-specific findings as well as a collective finding. For Issues 1-4, 9 and 10, NRDC will present argument as to each individual utility as well as argument regarding the collective finding.

FMPA, JEA, RCID and COT:

Based on the Application, the supplemental materials (including interrogatory responses, production of documents and answers to deposition questions) and based on evidence presented at the hearing (through witness direct, rebuttal and cross examination), the Applicants have failed to demonstrate the need for the proposed Taylor Energy Center (TEC) based on the need for electric system reliability and integrity.

As explained in more detail below in response to Issue 4, the Applicants have failed to adequately consider whether reasonably available demand side management (DSM) measures might mitigate or defer the need for new capacity for each of the project participants. Additionally, as explained in detail in response to Issues 3, 5 and 9, despite the virtual certainty of $CO_2$ regulation during the lifetime of this plant, the Applicants have failed to adequately consider costs associated with compliance with $CO_2$ regulations. Both of these failures undermine the Applicants' ability to demonstrate need for the proposed coal plant based on electric system reliability and integrity.

The appropriate identification and deployment of DSM measures can function to reduce energy use thus reducing overall demand for electric power. [T. 1166] Appropriately designed and coordinated DSM measures can also serve to reduce demand peaks, reduce aggregate coincident peak and shift the timing of peak demand. [T. 479-83] Thus, an aggressive and well managed portfolio of DSM programs can help to prevent stresses on the system and limit potential disruptions in service. Accordingly, DSM itself has benefits for system reliability and integrity, benefits that were not adequately considered by the Applicants in connection with this project. The Applicants' failure to adequately address the availability and appropriateness of additional DSM programs not only has the result of overestimating the capacity need (or the timing of that capacity need), it also has the effect of overestimating the need for additional capacity for purposes of system reliability and integrity.

The record demonstrates that well designed and implemented DSM measures are as reliable as, or more reliable, than new capacity and have a number of very important attributes that can contribute significantly to system reliability and stability. [T. 905-08, 912-14] As just one example, rail problems and other infrastructure issues related to fuel acquisition and delivery have the potential to present reliability and integrity issues that do not arise in connection with DSM.

The Applicants' failure to adequately account for the cost of $CO_2$ , as discussed in detail in Issue 5 below, also raises serious questions about the impact of TEC on system reliability and integrity. To the extent that $CO_2$ emissions create significant new cost associated with coal-based power generation in Florida, and those costs have not been appropriately identified and accounted for in the process of evaluating the expected cost of operation the proposed plant, such cost could create a significant and substantial disruption in the reliability and integrity of the system.

Accordingly, because the Applicants have not adequately or appropriately evaluated the potential for DSM and because they have not reasonably accounted for likely regulatory costs associated with the regulation of $CO_2$, they have not demonstrated that the proposed TEC facility is needed or appropriate, taking into account the need for electric system reliability and integrity.

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

**POSITION:** **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.**

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

**POSITION:** **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.**

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FMPA: The base case forecast of demand and energy for FMPA shows net energy for load (NEL) average annual growth rates of 2.5 percent from 2007 until 2009 and 2.0 from 2010 through 2024. [Ex. 58, p.B.3-7, Table B.3-3]. Forecasted base demand is initially 7,317 GWH in 2006 and grows to 9,456 GWH in 2024. [Ex. 58, p.B.3-9, Table B.3-3] Based on this energy and demand forecast, using revised capital costs for TEC and base case assumptions, the least cost IRP for FMPA without TEC included greenfield circulating fluidized bed units in 2012 and 2014, a brownfield LMS 100 CT in 2018 and a greenfield CFB in 2020. [Ex.3, Errata Sheet, page 4] This self-build least cost IRP was $417.1 million more expensive than participation in TEC. [Ex. 3, Errata Sheet, page 4] , Additionally, sensitivity analyses were considered by the Applicants for FMPA with other jointly and individually owned self-build options: 1) a 3x1GE 7FA (natural gas fired) and Three-Train 1x1 IGCC (coal and pet coke) jointly owned with JEA with an in-service date of 2012; 2) all natural gas fired plan at both existing and greenfield sites with an in-service date of 2011; 3) a second greenfield site 250 MW circulating fluidized bed (CFB) coal unit coming on line in 2016 jointly owned with JEA in addition to the TEC unit in 2012; 4) two biomass supply side plans adding the unit in 2011, one with and one without TEC and 5) use of only Powder River Basin (PRB) coal for TEC. [Ex.3, Revised Table B.6-21] For each sensitivity case run, the integrated resource plan (IRP) with TEC had a lower cumulative present worth cost (CPWC) than any IRP without TEC. [Ex. 3, Revised Table B.6-18] Finally, when compared with the TEC base case, both bids received by the Southern Company (pulverized coal unit and 2x1 combined cycle unit) were more expensive. [Ex. 3, Revised Table B.6-22]

JEA: The base case forecast of demand and energy for JEA shows net energy for load (NEL) average annual growth rates of 2.2 percent from 2006 until 2024. [Ex. 17, p.C.3-8, Table C.3-5, T. 654]. Forecasted base demand is initially 14,077 GWH in 2006 and grows to 20,851 GWH in 2024. [Ex. 17, p.C.3-9, Table C.3-5] Based on this energy and demand forecast using base case assumptions for TEC, JEA's least cost IRP without TEC included construction of a brownfield LMS100 CT in 2011, a brownfield CFB in 2012, a second brownfield CFB in 2014, a second brownfield LMS100 CT in 2019, a brownfield 1x1 combined cycle in 2020, a brownfield IGCC unit in 2022, a greenfield LMS 100 CT in 2023 and a second greenfield LMS100 CT in 2024. [Ex.58 at page C.5-12] This least cost self-build IRP without TEC was $38.1 more expensive than participation in TEC. However, under JEA's high load and energy growth sensitivity analysis, an IRP without TEC was $12.7 million dollars cheaper on a CPWC basis than the IRP containing TEC in 2012. [Ex. 3, Revised Table C.6-18] Additionally, sensitivity analyses were conducted by the Applicants for JEA with the same alternative self-build options as those considered by FMPA. [Ex.3, Revised Table C.6-21] For each sensitivity case run, the IRP with REC had a lower CPWC than any IRP without TEC. [Ex.3, Revised Table C.6-21] Finally, when compared with the TEC base case, both bids received by the Southern Company (pulverized coal unit and 2x1 combined cycle unit) were more expensive. [Ex. 3, Revised Table C.6-22]

RCID: RCID has experienced an average annual electric demand growth rate of 1.0 percent for the last eight years. RCID's Witness Guarriello did not know the average annual electric demand growth rate for the last five years. [T. at 723]. RCID's forecasted base energy requirement is initially 1,259 GWh in 2006 and grows to 1,395 GWh in 2025, an average annual increase during the study period of 0.5% . [Ex. 18, p.D.3-2, Table D.3-1; T. 713] Based on this energy and demand forecast, using revised capital costs for TEC and base case assumptions, the least cost expansion plan for RCID without participation in TEC extends its TECO power purchase agreement thtough 2017, constructs a brownfield LM6000 1x1 combined cycle unit in 2011, a brownfield LM6000 1x1 combined cycle unit in 2014, and two brownfield LM6000 1x1 combined cycle units in 2018. [Ex. 58, Page D.5-9] This least cost self build option results in higher costs of $255.6 million over participation in the TEC unit. Additionally, sensitivity analyses were conducted by the Applicants for RCID with the same alternative self-build options as those considered by FMPA. For each sensitivity case run, the IRP with REC had a lower CPWC than any IRP without TEC. [Ex.3, Revised Table D.6-13] None of these alternatives were cheaper than participation in the TEC unit. Finally, when compared with the TEC base case, both bids received by the Southern Company (pulverized coal unit and 2x1 combined cycle unit) were more expensive. [Ex. 3, Revised Table D.6-14]

Tallahassee: The base case forecast of demand and energy for COT shows net energy for load (NEL) average annual growth rates of 1.7 percent from 2007 until 2025. [Ex. 20, p..E.3-5, Table E.3-3]. Forecasted base demand is initially 2,976 GWh in 2007 and grows to 4,025 GWh in 2025. [Ex. 20, p.E.3-

5, Table E.3-3, T. 748] Based on this energy and demand forecast, using revised capital costs for TEC and base case assumptions, COT's self build least cost IRP without TEC included a LMS100 CT in 2011 and participation in a second CFB unit in 2016 with JEA. [Ex. 3, Revised Table E.6-18] This self build plan was $188.6 million more expensive than TEC. [Ex. 3, Errata Sheet at page 19] Additionally, sensitivity analyses were conducted by the Applicants for COT with the same alternative self-build options as those considered by FMPA. For each sensitivity case run, the IRP with TEC had a lower CPWC than any IRP without TEC. [Ex.3, Table E.6-21] Finally, when compared with the TEC base case, both bids received by the Southern Company (pulverized coal unit and 2x1 combined cycle unit) were more expensive. [Ex. 3, Revised Table E.6-22]

ARGUMENT:

Issue 2: 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 forecasts. As discussed in Issues 1, 3 and 4, NRDC questions whether these projected capacity and energy needs could have been substantially reduced or can be most cost-effectively met by demand side management (DSM) programs rather than building any supply side option analyzed by the Applicants.

Issue 9: Several of the assumptions used in the development of the collective base case and sensitivity study IRPs with TEC and the self-build options and associated sensitivity study IRPs for each Applicant are highly flawed.

First, no IGCC unit was modeled for any Applicant until 2018 due to the Applicants' conclusion that the new generation of IGCCs was "emerging", unproven technology. [T. 338, 1090] This conclusion is unsupported by the record. Witness Furman, a retired consulting engineer, testified that the new generation of IGCC plants could operate at a capacity factor of 80% while burning inexpensive pet coke which is comparable to the 85% capacity factor projected for TEC. [T. Ex. 82, page 3] Witness Rollins testified that the existing TECO IGCC unit had achieved a lifetime availability factor of 74%. [T. 342] Witness Klausner admitted that TECO's "old technology" IGCC plant placed in service in 1992 has maintained an availability factor "in the 80% range" in 2006 and over the last two years. [T.1095-6, 1267] TECO's plant manager Mark Hornick has stated that TECO's current unit has achieved availabilities over 85%. [Ex. 82 at 20] Further, General Electric, a major manufacturer of IGCC units, has reported availability factors of 90% for its four China units over the last three years. [T. 34; Ex.. 82 at 20] Finally, Orlando Utilities Commission (OUC) in conjunction with the Southern Power Company-Orlando Gasification LLC (Southern Power) requested and received approval from the Commission to construct a 282 MW "new technology" IGCC unit with availability factors at times greater than 74% which were guaranteed by Southern Power.[1] [T. 1267; Ex.1, Rollins Deposition at 46-7] Since the self-build option considered by OUC was a subcritical coal plant like Stanton Unit 2 with similar availability factors to TEC, it is fair to assume that the availability factors being guaranteed by the Southern Company are equivalent to those of TEC. [Ex.1, Rollins Deposition at 46-7] It is hard to imagine that the Southern Company, hardly a non-profit institution, would be willing to risk the payment of "substantial penalties" for non performance of its IGCC unit.[2] Further, the unreliability of the new generation of IGCCs and their in ability to maintain availability factors equivalent to that of pulverized coal units is placed in question by the fact that on September 29, 2006 the Department of Energy reported that the construction of 28 IGCC projects are being proposed by utilities and independent power producers in the United States. [Ex. 82 at page 18] One of these proposed IGCC plants is TECO's 630 MW unit with $CO_2$ capture which has a projected in service date of 2013. [T. 27] The above data in the record does not support completely eliminating IGCC technology from consideration in the base case and sensitivity IRPs.

[1] *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*, Docket No. 060155-EM, Order No. PSC-06-0457-FOF-EM, issued May 24, 2006, at p.3.

[2] *Id.*

Second, the Applicants make much of the fact that all IGCC units in the United States to date, including TECO's existing and proposed IGCC untis, have received federal funding in the form of either direct grants or tax credits which allowed those projects to be cost-effective when compared to pulverized coal technologies. [T. 38-9, 341] The Applicants have also conducted a sensitivity study using a Three-train 1x1 IGCC unit in 2012 which resulted in higher CPWC than TEC. [T. 339] However, the Applicants did not include any subsidies from the Department of Energy (DOE) in this sensitivity study. [T. 339-40] Such funds may have been available to the Applicants. On October 5, 2003 the Taylor County Commission by resolution requested that TEC request federal funding for an IGCC plant. [T. 406-7] No formal written request was ever made by the Applicants to DOE for such funding nor does DOE have a record of any communications at all with the Applicants. [T. 408; Ex. 102]

Third, conflicting testimony was given regarding $CO_2$ capture technologies should $CO_2$ become regulated. Several of the Applicants' witnesses testified that there was carbon capture equipment in the currently available in the development stages that could be retrofitted to pulverized coal units to capture $CO_2$ . [T.341, 832] Several of the Applicants' witnesses also testified that $CO_2$ sequestration was an "emerging" technology that had only been proven on a small scale in industrial "process type" applications, not with regard to an IGCC unit. [T.341, 1090-1] However, Witness Klausner verified that a gasification unit has been operating in North Dakota and sequestering $CO_2$ emissions. This unit is described in some detail in Exhibit 82 [Ex. 82 at 21-2] Witness Preston did not include the cost of any retrofit $CO_2$ capture technology in his PRISM model. [T. 1043; Ex. 1, Preston Depo. at 63] The only $CO_2$ capture technology included in the PRISM model is the cost of partial sequestration of $CO_2$ by an IGCC unit. [T. 1031; Ex.1, Preston Depo. at 41] The availability of TEC to be economically retrofitted when $CO_2$ becomes regulated directly impacts the cost of continuing to operate TEC as a baseload unit at the 90% availability factor assumed in all of the IRP base case and sensitivity models.

Fourth, the forecasted cost of the various types of coal, natural gas and diesel developed by

Witness Preston reflects the influence of the price of mercury, $NO_x$ and $SO_2$ (and in the $CO_2$ sensitivity study, $CO_2$) emission allowances. [T. 1031; Ex. 37-40] Witness Myers added the cost of transportation to the forecasted commodity costs developed by Witness Preston to arrive at the delivered cost for the various fuels used in the IRP modeling by Witness Kushner. [T. 972; Ex. 27-30] This adjusted price was used by Witness Kushner in his IRP analyses. [T. 973] All of the assumptions used by Witness Preston in the development of his commodity prices for the various types of coal were based on federal emission control standards for mercury, NO2 and SO2, not Florida emission control standards for those substances. [T. 346, 1031; Ex.1, Preston Depo. at 32] Florida has proposed its own state implementation plan for the Clean Air Interstate Rule (CAIR ), which deviates from the federal standards. This state implementation plan has been challenged. [T. 346] Because of this challenge, DEP has not submitted its state implementation plan to the federal Environmental Protection Agency (EPA) for approval. [T. 347] Thus, no final Florida implementation plan for $NO_2$ and $SO_2$ substances currently exists. [T. 347 ] Further, Florida is likewise required to develop a state implementation plan for the Clean Air Mercury Rule (CAMR). Florida has done so. However, Florida's proposed implementation of CAMR is substantially different that the federal proposal, e.g., it will withhold 25% of the available mercury allowances for 6 years between 2012 and 2017 and allocate a certain number of allowances each year for new units. [T.326] DEP has released an administrative order quantifying the initial mercury allowances available to substantially affected persons under the CAMR program. [T.348-9; Ex. 1, Staff's Second Set of Interrogatories No. 63] This administrative order is a preliminary allocation subject to challenge under Chapter 120, F.S., by all substantially affected persons. For that reason it is also not final. Even if Florida's CAMR implementation plan were final, Witness Preston did not make any adjustments to his PRISM model to take Florida's specific CAMR implementation criteria into account. [Ex.1, Preston Depo. at 30] 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.

Fifth, certain cost assumptions used in the development of the IRP are inconsistent. For example, Witness Hoornaert included the cost of activated carbon injection for mercury removal in Phase 2 of CAMR regulation in his revised cost estimates for TEC, but did not include the increased variable O&M costs necessary to operate that pollution control equipment. [T. 829]

Sixth, the Applicants have made basic and highly erroneous assumptions with regard to $CO_2$ regulation and its cost. The first assumption is that because $CO_2$ is not regulated now, it will not be regulated within the 40 year lifetime of TEC. [T. 1248, 1269] The second assumption is that even if $CO_2$ is regulated during the life of TEC, it is impossible at this time to develop a reasonable forecast of $CO_2$ emission allowance prices. Any $CO_2$ emission allowance forecast, according to the Applicants, is simply too speculative to rise to the level of competent substantial evidence upon which the Commission can base any factual findings regarding the operating and capital costs of the various supply and demand side options evaluated in this case. [T. 1248, 1270] Therefore, it is entirely appropriate, according to the Applicants, to use the POWROPT and POWRPRO models to develop an IRP base case which does not include any cost associated with $CO_2$ emission allowances or $CO_2$ capture equipment either directly or indirectly in the form of fuel prices developed under a $CO_2$ regulation scenario. Neither of these assumptions is correct.

With regard to the first assumption, the very actions of the Applicants belie this conceit. Witness Gilbert testified that prudent utility planners would consider and evaluate the likelihood of $CO_2$ regulation. [T. 674-6] As a utility with a 50% coal portfolio, JEA has internally evaluated the cost of $CO_2$ regulation on its system. [T. 671-2, 676] This internal study used the McCain-Liberman bill as the basis for its assumptions, and unlike the analysis performed by Witness Preston, decreased the cap on $CO_2$ emissions over time to match the provisions of the McCain-Liberman bill. [T. 678-9] JEA's internal study produced different results than that of Witness Preston, some years higher, some years lower. [T.

678] The analysis done by JEA did not consider the interaction of fuel and $CO_2$ emission allowances and is therefore comparable to the numbers produced by Synapse Energy Economics. [T. 676-7] Tallahassee also did a $CO_2$ sensitivity study to evaluate the impact of $CO_2$ regulation on its proposed IRPs using ICF integrated $CO_2$ emission forecasts as well as those of Synapse Energy Economics. [Ex. 107 at page 5] The assumption that $CO_2$ regulation will not occur during the 40 year operating life time of TEC is simply wrong and one even the Applicants don't truly believe.

The Applicants' actions are consistent with the testimony of Witness Lashof, that based on the number of bills which have been filed in the United States Senate and House, acknowledged by the Applicants at deposition and hearing, and actions taken by an increasing number of individual states to regulate $CO_2$, it is a virtual certainty that $CO_2$ emissions will be regulated during the 40 year operational life of TEC. [T. 850-1, 1038-9, 1063-66; Ex. 1, Preston Depo. at 47] Florida editorials have been written about $CO_2$ regulation, Florida is considering regulating $CO_2$ emissions should the federal government not do so and the issue of $CO_2$ regulation is being discussed and debated virtually daily in the national and Florida media. [T. 676-7, 850] In short, it is general knowledge that global warming is a concern and $CO_2$ regulation is a means of addressing that concern. The Commission does not have to ignore its own general knowledge to reach the conclusion that $CO_2$ regulation is likely to occur during the 40 year operating life of the TEC unit.

Once having determined that $CO_2$ regulation is likely to occur during TEC's operational lifetime, is it prudent for the Commission to ignore reasonable forecasts of that cost and to consider its impact on the total cost of operating TEC? No. Have reasonable forecasts been presented here? Yes. The Synapse Energy Economics low, mid and high forecasts are reasonable and should be used to develop a realistic base case and sensitivity analyses for TEC. [T. 852; Ex. 79] To the extent that the Synapse Energy Economics forecasts were not developed in conjunction with fuel price forecasts, the Applicants can use the "full blown" $CO_2$ emission "multiclient" allowance forecast prepared by Hill & Associates testified to by Witness Preston. [T. 1045-6] Since that $CO_2$ forecast was developed using the PRISM model, it will produce an integrated fuel and emission allowance forecast and has already been prepared. Alternatively, the PRISM model could be run again using the internal assumptions developed by JEA if those assumptions, as it appears from the testimony of Witness Gilbert, are reasonably consistent with the McCain-Liberman bill again producing a forecast with integrated fuel and emission cost forecasts. Alternatively, the Applicants could rely upon the U.S. Department of Energy's Energy Information Agency's estimation of $CO_2$ costs, which are publically available and are contained in Exhibit 112. Using any of these fuel and emission allowance figures in the POWROPT and POWRPRO models will produce a more accurate IRP which may or may not find TEC to be the most cost-effective alternative available. One thing is certain, using realistic $CO_2$ emission allowance forecasts will increase the operational cost of TEC relative to all natural gas and IGCC units with $CO_2$ capture and sequestration.

Were $CO_2$ emission allowances properly evaluated by the Applicants? No. As discussed in more detail in Issue 5, the assumptions used in the $CO_2$ sensitivity analysis prepared by Witness Preston were so unrealistic that his forecast of $CO_2$ emission allowance costs can't be reasonably relied upon. Thus, the $CO_2$ allowance scenario fuel price forecast developed by Witness Preston and, therefore, the delivered price forecast developed by Witness Myer under a $CO_2$ regulation scenario, do not accurately reflect the cost of coal, pet coke, natural gas and diesel over the study period. That being the case, the $CO_2$ sensitivity studies run by Witness Kushner for the Applicants individually and collectively and do not accurately reflect the true result of a $CO_2$ regulated scenario.

When more realistic assumptions for $CO_2$ regulation are used, in this case the Synapse Energy Economics' high $CO_2$ forecasts, participation in TEC has been demonstrated to cost the City of Tallahassee $126,751,000 more than an all gas IRP. [T. 781; Ex. 107 at page 5] Although a PRISM $CO_2$ sensitivity analysis was requested by NRDC which would have used the same parameters for electricity demand growth, same amount of nuclear capacity and same amount of energy produced by renewables or other non-emitting sources as that used in the TEC base case models to produce an accurate IRP $CO_2$ sensitivity study, this request was denied. [Order PSC-07-0032-PCO-EU, issued on January 9, 2007] Had this sensitivity been done, the results could have been inputs into a $CO_2$ IRP sensitivity case that was directly comparable to that of the TEC base case. Unfortunately, that information is not before the Commission.

Finally, there are several problems with the November, 2005 Request For Proposals (RFP, bid) which impacted its ability to fairly assess power purchase supply side alternatives available to the Applicants. First, the bid stated that it preferred solid fuel (coal, nuclear) and "mature technologies" but did not limit other types of technologies (natural gas) that would be considered in its bid if "superior to solid fuel alternatives on the basis of price and nonprice criteria." [T. 937-8, 949-50] However, a bid for an IGCC plant that included a request for DOE funding would not have been considered responsive and would have been rejected. [T. 431-2] Since the Applicants themselves knew that all operating IGCC units in the United States had received some sort of DOE funding, this decision virtually assured that no IGCC proposal would be considered as an alternative to TEC. Second, the cost of the entire 3,000 acre TEC site, not just the land necessary to construct the 797 MW coal plant bid by Southern Company, was added to Southern Company's bid, i.e., enough land to support two 800 MW coal plants. [T. 830, 940] The Applicants have stated that they will only seek ultimate site certification for one unit of approximately 800 MW gross size. [T. 830] The cost of the land added to the Southern Company bid should have been adjusted to reflect the one unit being bid. Third, only seven companies attended the prebid conference, only two of those filed a notice of intent to bid and only one company, the Southern Company, actually submitted bids. [T. 938-39] The limited participation of qualified potential bidders after the prebid conference is highly suspicious. Fourth, although the Southern Company coal plant bid was an "indicative offer", meaning that Southern Company had 45 days to "firm up their price", the Applicants did not approach the Southern Company to see if further price or nonprice concessions would be made to make their bid more competitive with that of TEC. [T. 943-44] Fifth, a busbar screening analysis using revised TEC costs was done comparing the Southern Company bids with that of TEC. [T.941-2] Additionally, a sensitivity analysis was done including a $7 per ton cost for $CO_2$ allowances in 2012 escalating at 2.5% per year over the Southern Company 20 year bid period. [T. 941-3] As discussed in more detail in Issue 5, this cost is significantly lower than that projected by Synapse Energy Economics for the same time period although higher than the average $CO_2$ allowance cost predicted by Witness Preston of $6.64 per ton. [Ex. 79; Ex. 40] Use of the lower $CO_2$ allowance cost, would have skewed the results in favor of a coal rather than natural gas plant.

CONCLUSION:

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.

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

**POSITION:** **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.**

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<u>JEA:</u> Nothing in the record demonstrates that, for JEA, participation in TEC would increase fuel diversity. In fact, with or without TEC, JEA coal-based generating capacity remains virtually unchanged. In the Applicants' response to NRDC's First Set of Interrogatories, JEA provided an analysis of future coal capacity based on two alternative expansion plans - one with the TEC project and one without TEC. The analysis reflected the alternative expansion plans presented in the Application at Tables C.5-6 and C.5-7. In its interrogatory answers the Applicants provided figures representing JEA's generating capacity by fuel type for the years 2015, 2020, 2025, 2030 and 2035. [Ex. 108, p.14-20] JEA's own exhibits show that JEA's coal capacity with and without TEC for each year are as follows:

- 2015: 52.7 % coal capacity with TEC; 49.1% coal capacity without TEC;
- 2020: 51.6 % coal capacity with TEC; 45.6% coal capacity without TEC;
- 2025: 46.4 % coal capacity with TEC; 46.9% coal capacity without TEC;
- 2030: 46.4 % coal capacity with TEC; 46.9% coal capacity without TEC;
- 2035: 46.4 % coal capacity with TEC; 46.9% coal capacity without TEC;

As this document clearly illustrates, the percent of JEA's capacity that is associated with coal-based generation remains roughly 50 percent whether or not JEA participates in TEC. [T. 671-4] In fact, for the last three years modeled (2025, 2030 and 2035), a *greater* percentage of JEA's generating capacity is coal-based *without* TEC.

Accordingly, for JEA, it is evident that this particular project will have no meaningful impact on fuel diversity, and therefore, TEC is not needed for fuel diversity and supply reliability as this criterion is used in §403.519, Florida Statutes.

Moreover, because JEA's generating capacity is currently about 50% coal-based, it would be significantly affected by the regulation of $CO_2$ emissions - particularly if such emission limitations involve a significant cost for $CO_2$ allocations (which as discussed in Issue 5 is very likely). Thus, because of its significant reliance on coal as compared to the other participants, JEA is potentially more vulnerable to the cost-related effects of $CO_2$ regulation, and may not benefit at all or as much from increased coal-based generating capacity. As discussed below in Issues 5 and 9, because the Applicants here did not conduct an appropriate assessment of $CO_2$ costs, it is unclear precisely to what extent $CO_2$ regulation may affect JEA and whether an increase in coal capacity would be beneficial or detrimental.

ALL APPLICANTS (FMPA, JEA, RCID and COT):

For JEA, as for each of the other participants, to the extent that coal diversity is a valuable objective to help insulate electricity rates from natural gas price volatility, a full and unbiased analysis would demonstrate that integrated gasification combined cycle (IGCC) and not pulverized coal is likely to be the best and least cost option. The Applicants have failed to perform an adequate analysis of IGCC. The Applicants inappropriately concluded that IGCC would not be an available and mature technology until 2018, they failed to accurately assess the availability and reliability of IGCC, and they failed to fully and accurately assess the cost advantages of IGCC related to future $CO_2$ regulation.

In general, the Applicants made two assertions regarding IGCC. First, that it is not a currently available or mature technology. Second, that it is not cost competitive when compared to pulverized coal. The fact is, however, that the Applicants' analysis in this proceeding fails to demonstrate the truth of either of these assertions.

In his testimony, Witness Rollins explained that numerous supply-side alternatives, including

IGCC, "were eliminated from further consideration" before being evaluated on a levelized cost basis. [T. 330] These options were eliminated based on a subjective judgment about "the technology's reliability and feasibility to meet the Participants' capacity needs." [T. 330] In particular, with regard to IGCC, the Applicants "characterized IGCC . . . as an emerging technology" and concluded, based on a number of questionable assumptions, that this advanced coal technology would not be available for commercial operation until 2018. [T. 338]

According to Witness Rollins, the 2018 availability date was based on the assumption that currently proposed IGCC units (such as the proposed Orlando Utilities unit) would begin operation in the 2010 time frame. The Applicants assumed further that the technology would need "three years of demonstrated performance." Finally, the Applicants assumed that "it takes a couple of years to permit and license an IGCC unit and then probably about three years to construct it." [T. 339] Accordingly, the total lead time based on these assumptions was 2010 plus eight years for demonstration, permitting and construction; allowing for an in-service date of no earlier than 2018.

This analysis is flawed in several respects. First, the Applicants significantly overestimate the time required for the commercial availability of IGCC. As indicated in the record, modern coal gasification is not a new technology - in fact, coal gasification has been actively used since the 1930s. [Ex. 82 at 14] According to the Gasification Technologies Council, in 2004 there were about 385 gasifiers operating world wide at about 117 plants, with a total capacity equivalent to about 45,000 MW. *Id.* These gasifiers use predominately coal and petroleum residuals, and produce chemicals, liquid fuels and power, among other things. [Ex. 82 at 14] It is clear that gasification is a well established technology with which there is a tremendous amount of experience.

Obviously, combined cycle power generation is a well established technology - and IGCC is simply the joining together of a gasification unit and a combined cycle power block.. While the U.S. utility industry has relatively little experience combining gasification units with combined cycle power generation, there is considerably more experience - particularly recent experience - than the Applicants suggest. While acknowledging that there are at least "20 power producing IGCC projects operating throughout the world", the Applicants insinuate that information regarding these units is unhelpful because "only four . . . have the ability to use coal or petcoke." [Ex. 5, p.A.6-65] To the contrary, there are at least seven currently operating IGCC plants that use coal and/or petcoke to generate electricity or to cogenerate electricity and some other product. [Ex. 82, p. 15] Moreover, the tremendous experience related to non-coal IGCC and non-IGCC coal gasification cannot be dismissed as irrelevant.

The Applicants make much of the fact that the two existing U. S. IGCC plants, the Wabash plant in Indiana and Tampa Electric Company's Polk power plant, have had relatively low long-term availability factors - in the range of about 75%. [T. 367-8] In effect, the Applicants would have the Commission believe that nothing has been learned about how to effectively and efficiently build and operate a commercial IGCC plant since the Polk and Wabash plants were built and brought into service in the U.S. more than a decade ago. In this regard, the Applicants would have the Commission rely on an apples-to-oranges comparison of fifteen year old IGCC technology to new super critical pulverized coal technology. This comparison is simply inappropriate.

While the Applicants attempt to draw the Commission's attention to very small universe of existing units as a reflection of the feasibility, availability and reliability of IGCC in general, such a myopic view of the current state of IGCC is both inappropriate and misleading. Indeed, several IGCC plants have been built worldwide since 2000, and these plants more accurately reflect the type of performance that one would expect from the new generation of IGCC. [Ex. 82, p.15] Among other things, these newer units have been able to consistently demonstrate operational availability at or above 90 percent - one of the main concerns that the Applicants identify with respect to IGCC. [Ex. 5, p.A.6-65] Indeed, Witness Rollins states accurately that there are no issues regarding adequate availability for new IGCC units "[i]f the gas turbine(s) can operate on backup fuel when syngas is not available." [Ex. 5, p.

A.6-66] This view is corroborated in the record. [Ex. 82 at 11] Alternatively, some new IGCC units are being designed with a backup gasifier to ensure an uninterrupted supply of fuel for the turbines. [*Id.*]

In fact, the only issue the Applicants raise with respect to the performance of this new generation of IGCC units (indeed, the only issue they can raise) is that the fuel sources for the existing fleet of new IGCC units are not identical to the fule source for the proposed TEC unit. [T. 1096] For example, when asked why the Applicants considered IGCC and not SCPC to be an "emerging technology", despite the Applicants' admission that there have been very few SCPC plants built in the U.S., Witness Rollins answered: "The distinction is that there are significant numbers of supercritical pulverized coal gasification plants that are performing very well in both Europe and Japan. There are very few integrated coal gasification plants that are performing anywhere that *generate electricity and burn solid fuel . . .*" [T. 359] This issue, however, is a red herring. As presented in Ex. 82 at pages 14 and 15 (and as acknowledged in the Application itself at page A.6-65) there are, in fact, numerous gasification and IGCC units that operate worldwide. While the fuel and product characteristics may not reflect precisely what a TEC alternative would look like, these units nonetheless demonstrate that gasification technology and IGCCs are mature technologies. While fuel is associated with some difference in feed preparation and solids removal, the new European IGCC units use essentially the same equipment as would be used on any domestic petcoke-fired IGCC unit. [Ex. 82, p., 15]

Illustrating that IGCC is a technology that is currently available for commercial power production, there are now some 40 to 50 proposed gasification projects across the U.S., some 28 of which are IGCC power plants according to the Department of Energy. [T. 30; Ex. 82, p. 17-8] To characterize this technology as still "emerging" when it is being so heavily relied upon in the current fleet of power plant proposals across the country is disingenuous. Rather, in fact, the wide-spread reliance on IGCC shows that it is a technology that is not only currently available but one that the industry is actively pursuing.

Not only are IGCC plants available technology, they have several benefits over conventional pulverized coal technology that the Applicants have failed to adequately address. As relates to this proceeding, IGCC plants can produce electricity at a cost that is comparable to or less than a SCPC plant, in part because IGCC plants can operate using 100 percent petroleum coke (which is a cheaper fuel source than coal). [Es. 82, p. 3] Additionally, IGCC plants, unlike SCPC plants, can potentially utilize a broad range of fuels - including, coal, petcoke, natural gas, diesal and biomass. [Ex. 82, p. 29] Accordingly, IGCC is a dual-fuel (or perhaps multi-fuel) technology, which makes it even more attractive option from the perspective of fuel diversity and long-term supply reliability.

Moreover, IGCC plants can be equipped to capture $CO_2$ emission at a cost that is dramatically lower than the cost of controlling $CO_2$ from a SCPC plant. [Ex. 82, p.4-5] While Witness Rollins indicated in his testimony that he "thought" capture and sequestration of $CO_2$ was "something that's even further out than emerging", Witness Klausner acknowledged that active capture and sequestration of $CO_2$ is currently happening at a North Dakota gasification unit. [T. 1091] This testimony is corroborated by Ex. 82 at pages 21 and 22, describing the project at the Great Plains Synfuels Plant in Beulah, North Dakota, where commercial-scale $CO_2$ capture is taking place and in the Weyburn oil fields in Canada where $CO_2$ capture and sequestration has been taking place in connection with enhanced oil recovery (EOR) since 2000.

Dr. Lashof testified that $CO_2$ emission regulations are "virtually certain" within the lifetime of this plant. [T. 858] This assessment is based in large part on what science is telling us about global warming. [T. 854-5] Given that emissions of $CO_2$ will need to be reduced by 60 to 80 percent in order to stabilize atmospheric levels of $CO_2$ at concentrations low enough to avoid severe climate disruption, the Applicants' failure to specifically assess IGCC in connection with realistic $CO_2$ regulatory limits is particularly egregious. Exhibit 63, *What to Do About Coal* (Scientific American, Sept. 2006), describes in detail the considerable challenges facing the U.S. and the world with respect to controlling $CO_2$

emissions from coal, and the steps that will be necessary to meet this challenge (including significant reliance on carbon capture and sequestration. In light of these challenges, any commitment to new coal-based power production must include serious consideration of the likely affects of $CO_2$ regulation, and a meaningful evaluation of the cost implications of the regulations that will be required to avoid climate disruption. In this regard, as discussed in more detail in Issue 5, the Applicants' $CO_2$ sensitivity case grossly underestimated the likely cost of $CO_2$ allowances, and their evaluation of the cost benefits of IGCC is necessarily flawed.

It is worth noting again that the Applicants did not earnestly seek federal funding for IGCC. Witness Lawson testified that the TEC participants did not make any specific request to the U.S. Department of Energy (DOE) for funding to pursue IGCC, which might have made it an even more attractive technology option. [T. 341] While Witness Lawson states that the TEC participants did "investigate opportunities for federal financial assistance", he describes no specific direct interaction with DOE other than attending a conference that DOE representatives also attended and unspecified "continuing contact with the US DOE, the US EPA, and Congress". [T. 394] In fact, Witness Lawson testified specifically that the TEC participants "did not formally in writing request funding from the Department of Energy". [T. 408] Moreover, Witness Lawson testified with regard to the request for proposals for competing bids, that TEC would not have considered a bid requesting that the Applicants come with the bidder to DOE in order to secure funding for an IGCC plant to be a responsive bid. [T. 432]

Given the numerous cost-related advantages of IGCC, the Applicants'anemic evaluation of IGCC is incomplete and misleading. The analysis in the record consists of approximately one page each in Sections B, C, D and E. [Ex. 58, p. B.6-28, C.6-28, D.6-19-20, E.6-27-8] Notably, these evaluations do not specifically compare the cost of an IGCC unit to the cost of a SCPC unit in a carbon regulated scenario - a situation where IGCC has distinct and significant advantages whether or not $CO_2$ capture and sequestration is necessary.

CONCLUSION:

For the reasons discussed above, there is simply no evidence in the record to support a conclusion that JEA has a need for TEC based on the need for fuel diversity and supply reliability. Even is such a showing could be made, with respect to JEA and each of the other participants, an accurate analysis (including a realistic assessment of $CO_2$ costs and the costs associated with construction and operation of an IGCC unit) would show that the need for fuel diversity would be better addressed by the construction and operation of an IGCC unit.

**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?**

**POSITION:** **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.**

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FMPA: FMPA recognizes and acknowledges that it has an absolute statutory obligation under section 403.519 to "take into consideration conservation measures that might mitigate the need for the proposed plant" in connection with this need determination process. [Ex. 13, p.B.7-1] Remarkably, however, MPA has not truly evaluated either existing or reasonably available DSM measures for itself or for its members, and claims based on an inadequate and inappropriate analysis that no cost-effective DSM measure are available.

With regard to its members, MPA did not examine the existing DSM measures that its members currently employ, the effectiveness of the measures, the general availability of those measures to its members, or the potential availability of additional DSM measures. The direct testimony of Witness May included a list of several DSM measures, purporting to reflect measures offered by MPA members, [T. 462] That list included: Energy Audits; High Pressure Sodium Outdoor Lighting Conversions; Energy Star Programs; Energy Services for Energy Upgrades; Green Energy Programs; Load Profiling for Commercial Customers; and Fix-up Programs for the Elderly and Handicapped. [T. 462; Ex. 13, p. B.7-1 - B.7-2.2]

However, Mr . May testified at hearing that this list reflected DSM measures that may or may not be offered by FMPA member at any given time. [T.478] In fact, the Application indicates that these measures are offered or currently " being reviewed" - according to Witness May this means that some FMPA members may have offered these measures " at some point in time" or that FMPA members are "looking at opportunities to reduce their cost through demand side or conservation measures." [T.478, 487] In short, it is not clear which if any of these listed DSM measures are currently being offered by FMPA members. [T.478]

Indeed, Witness May conceded that FMPA did not ask its members, in connection with this Application, for the details of the effectiveness of the DSM measures that they implement, nor was he aware of the criteria FMPA members use to evaluate DSM effectiveness. [T.484] Moreover, FMPA did not explore, in connection with this application, whether there were cost-effective DSM measures - such as those specifically identified by COT - that may be available to its members. [T.485] Similarly, because Witness Kushner, who performed the DSM analyses for FMPA and JEA, was not aware of data regarding the effectiveness of DSM measures that FMPA's members were using, there is no way that FMPA can assure this Commission that opportunities for conservation and demand side management have been exhausted, or the FMPA is taking appropriate action to ensure DSM measures are being coordinated for maximum benefit. Therefore FMPA cannot state that there is a need for the new capacity reflected in the TEC proposal.

As Commissioner Arriaga suggested at hearing, unless FMPA (and the other TEC Participants) meaningfully evaluate conservation and DSM, this Commission cannot be assured that the need identified in the Application is the appropriate level of need. [T. 498] The following exchange is reflected in the Hearing Transcript at page 500:

> Commissioner Arriaga: "... it is a possibility that one your members could not be doing all of the necessary efforts to do the extremes necessary to have reliable DSM programs, cost effective, reliable DSM programs?"

Witness May: "Sure, its possible."

This exchange exemplifies the shortcoming of FMPA's analysis - without ever having even assessed what measure its members use, FMPA is no position to demonstrate that the project for which it professes a need is actually appropriate. To adequately determine need, FMPA must necessarily perform a careful and comprehensive assessment of the DSM measures currently being used by its members, and a detailed evaluation of more broadly deploying existing measure to additional members, introducing new measures that are not currently in use, or better managing and coordinating the implementation of existing measures to maximize demand reductions.

While FMPA may not be in a position to itself implement DSM measures or impose or enforce DSM requirements on its members, it is in an ideal position to help its members identify appropriate DSM measures, and to help manage the deployment of such measure so as to provide maximum benefit to terms of peak load reduction. In this regard, Witness May indicated that it is the aggregate coincident peak that determines th amount of capacity needed by FMPA and that drives the cost of providing services. [ T.480-81] He indicated further that to the extent that FMPA could help to coordinate the implementation of members' demand side management programs so as to reduce aggregate coincident peak, that would maximize the effectiveness of those programs. [T. 482-83] However, Witness May conceded that FMPA has no plan or program specifically designed to accomplish this.[ T.482]

In the end, FMPA's analysis of conservation and DSM in connection with this Application was superficial at best. In addition to FMPA's failure to specifically assess its member's DSM programs, there is no indication that the generic assessment of 180 DSM measures performed for these Applicants (including FMPA) bore any relationship to the DSM opportunities that would best suit either FMPA's members or FMPA itself, or included the full range of potential available DSM options. These and other concerns about the adequacy and accuracy of this assessments were raised in testimony. [T.895-99, 904] It is worth noting in this regard, that comprehensive assessments of DSM opportunities often include evaluation of thousands of measures, and the analysis here evaluated less than 200. At hearing, Witness Kushner admitted that, in connection with identifying potential DSM measures for FMPA and JEA, he has not referenced or consulted any of the energy efficiency studies relied upon for COT's DSM analysis.[3] Nor did Witness Kushner provide a meaningful response when asked how he chose the 180 DSM measures that he evaluated, answering instead with a conclusion: " The 180 DSM measures that are listed and were evaluated represent a wide range of end uses and are pertinent to residential, commercial and industrial customer classes." [T.1174] Indeed, the Application itself also contains no meaningful explanation of what information or specific criteria were used to identify these 180 measure fir analysis.[4] [Ex. 58, p. A.9-1-A.9-4] Moreover, Witness Kushner indicated that he did not have the benefit of any information from energy service companies servicing FMPA members when the performed his DSM analysis. T.1207.[5]

Ultimately, FMPA concluded, based on Witness Kushner's analysis, that no cost-effective DSM measures were available. This conclusion relied entirely on the Rate Impact Test results of Witness Kushner's FIRE Model runs. In fact, Witness Kushner's analysis demonstrated that many DSM measures were cost-effective for FMPA based on the Participant Test an the Total Resource Test: in many cases DSM measures that did not pass the Rate Impact test passed *both* the Participant and Total Resource test (in some cases demonstrating dramatic effectiveness under these test - with customer

[3] The report prepared by Navigant for COT appropriately relied upon on a broad range of existing studies, regulatory materials and expert data that specifically evaluated the availability, cost and achievability of DSM savings. [Ex. 106 at 13-14]

[4] We note further that there is some evidence of discrepancies in the assumption used for Witness Kushner's DSM assessment and the DSM assessment performed for COT. In particular, at hearing Witness Kushner confirmed that his analysis assumed a lower energy saving for at least one DSM measure compared with COT's analysis. [T. 1180-81] These kinds of assumptions are critical to the accurate calculation of DSM value. [ T.897]

[5] Additionally, in response to a question regarding whether Witness Kushner consulted any information to identify benchmarks for what a reasonably DSM goal might be for FMPA. he responded "No. My analysis didn't consider what would be a reasonable goal per se. My analysis evaluated the 180 measure that have been presented." [T.1207]

benefits up to *184 times* greater than costs). [Ex. 58, Tables B.7-7,B.7-10] According to Witness Kushner, if all measures that passed the Participant and Total Resource tests were implemented for FMPA, it could save about 200MW of otherwise needed capacity. [T.1190] The Commision should not turn a blind eye to DSM measures that show significant potential for cost effectiveness simply because they do not pass a rate impact measure; such an approach is out off step with utility regulation in other jurisdiction, and will prevent the State of Florida from making conservation and efficiency a serious element of its strategy for addressing growth and energy demand issues. The Commision is not without the latitude in this case to require a mor robust and meaningful assessment of demand side alternatives to TEC.

Had FMPA performed an analysis similar to the one performed by COT (discussed below), it would have identified measures, as did COT, that are cost-effective to implement, and that have mitigated, and reduced, or deferred FMPA's need for new capacity. This would have saved money fir its members and provided additional opportunities for FMPA to coordinate DSM measures to reduce aggregate coincident peak demand. However, the Applicants did not perform this type of analysis for any Participant other than COT, and did not develop a dollar per megawatt hour levelized cost for any of the 180 DSM measures included in the generic analysis DSM analysis. [T.1170][6]

As discussed above, it is evident from the record that FMPA performed no meaningful assessment of DSM on its own, and that the generic DSM assessment that Witness Kushner performed was inadequate. It is simply not credible that only COT was able to find cost-effective DSM measures, and that the other Applicants could not find a single cost-effective measure between them.[7] Accordingly,

[6] In COT's analysis, the levelized cost of each DSM measure was screened against like-duty cycles to determine cost effectiveness. T.1168. [Ex. 106, Navigant Report; Ex. 58, at A-9-4, E. 7-1through E.7-15]

[7]A recent study in California was able to identify significant untapped energy efficiency even in that state. [Ex. 60, *California's Secret Energy Surplus*] In general, this report evaluated potential energy and peak demand savings from energy-efficiency measures (as opposed to conservation measures), and it shows that there is nearly 15,000 MW of technically feasible peak demand savings, and 10,000 MW of economic peak demand savings in the

FMPA has failed to demonstrate that conservation and DSM has been meaningfully considered.

JEA: As was the case with the other Participants, JEA acknowledged its statutory obligation under section 403.519 to "take into consideration conservation measures that might mitigate the need for the proposed plant." [Ex. 17, at C.7-1] Also, consistent with the other TEC Participants, with the exception of COT, JEA failed to meaningfully assess the potential for additional DSM savings.

JEA currently implements only two DSM programs: an energy audit program and a "Green Built Homes" initiative. [T.667][8] Given that JEA is the largest municipal utility in the State of Florida. the absence of a more aggressive DSM portfolio is particularly troubling. [T.663]

As discussed in connection with FMPA, above, the evaluation of potential DSM opportunities for JEA was limited in this proceeding to the assessment performed by Witness Kushner using the FIRE Model. JEA did not perform an independent assessment of existing DSM measures or of potentially available additional DSM measures. As with FMPA, that assessment evaluated 180 DSM measures, and found not a single DSM measure that would be cost-effective. [Ex. 17, at C.3-17] As with FMPA, this conclusion relied entirely on the results of the Rate Impact Test. And for JEA, as with FMPA, Witness Kushner's analysis demonstrated that many DSM measures were cost-effective for FMPA based on the Participant Test and the Total Resource Test. In many cases DSM measures that did not pass the Rate Impact Test passed *both* the Participant and Total Resource tests (in some cases demonstrating dramatic effectiveness under these test-with customer benefits up to *145 times* greater then costs). [Ex. 58, Tables C.7-7, B.7-10] According to Witness Kushner, if all measures that passed the Participant and Total Resource tests were implemented for JEA it could save about 100MW of otherwise needed capacity. [T.1190] The Commission should not turn a blind eye to DSM measures that show significant potential

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State of California- a state that has already taken very aggresive steps to maximize DSM. [Ex. 60 at ES-1.

[8] While JEA also implements a "clean power program" that seeks to increase renewably energy resources, this program does not include an element that specifically targets energy efficiency or conservation. [T.665-66]

for cost effectiveness simply because they do not pass a Rate Impact measure. As discussed above, such an approach is out of step with utility regulation in other jurisdiction, and will prevent the State of Florida from making conservation and efficiency a serious element of its strategy for addressing growth and energy demand issues. The Commission is not without the latitude in this case to require a more robust and meaningful assessment of demand side alternatives to TEC.

Had JEA performed an analysis similar to the one performed by COT (discussed below), it would certainly have identified measures, as did COT, that are cost-effective to implement, and that may have mitigated, reduced, or deferred JEA's need for new capacity. However, the Applicants did not perform this type of analysis for any Participant other than COT, and did not develop a dollar per megawatt hour levelized cost for any of the 180 DSM measures included in the generic analysis DSM analysis. [T.1170]

As discussed above, it is evident from the record that JEA performed no meaningful assessment of DSM on its own, and that the generic DSM assessment that Witness Kushner performed was inadequate. It is simply not credible that only COT was able to find cost-effective DSM measures, and that the other Applicants, including JEA, could not find a single cost-effective measure between them. Accordingly, JEA has failed to demonstrate that conservation and DSM has been meaningfully considered.

<u>RCID:</u> As did the other Participants, RCID recognized and acknowledged, in connection with this need determination process, its statutory obligation under section 403.519 to "take into consideration conservation measures that might mitigate the need for the proposed plant." [ Ex. 18, at D.7-1] Remarkably, in light of this obligation, RCID does not even attempt to actually evaluate DSM in the Application.[9] Rather, the Application merely asserts that "RCID and its customers continually evaluate

[9] RCID's main customer is Walt Disney World, which accounts for approximately 85% of its demand. The remainder of RCID's customers are commercial entities such as hotels, and ten residential customers. [T. 712]

opportunities for energy conservation, In light of the significant and successful conservation measures already in place within RCID's service territory...and RCID's ongoing commitment to evaluate new conservation opportunities, a separate conservation review was not performed prior to RCID's determination to participate in TEC." [Ex. 58, at A.9-1] Essentially, this is a statement affirming that RCID did not specifically evaluate either existing or potential available DSM measures in connection with this Application.[10] That understanding is confirmed with a review of the record in this proceeding.

In the portion of the Application specifically addressing RCID's consideration of DSM, RCID offers nothing more than further assertions regarding its customers' commitment to conservation and efficiency, and a very limited qualitative discussion of a few DSM measures that RCID or its customer currently employ. [Ex. 58, D.7-1 through D.7-5] In this discussion RCID generally lists the five main components of the U.S. EPA Energy Star Building program, including Building Tune-up; Green Lights program; Load Reductions; Fan System Upgrades; and Heating and Cooling Upgrades.[Ex. 58, D.7-1through D.7-4] RCID also generally describes its Energy Information System (including utility reporting systems, utility report card, and customer education), and briefly discusses two programs that RCID itself implements-the Green Lights program and a Thermal Storage facility. [Ex. 18, D7-2 through 7-5]. Nowhere in this discussion, elsewhere in the Application, or in the testimony at hearing, does RCID indicate that it ever specifically evaluated the potential for DSM, for either itself, for Disney, or for its non-Disney customers, in connection with this proceeding. In fact, as discussed above, RCID simply excused itself from any such assessment, based on the "unique" nature of its customer base.

Witness Kushner, who performed the DSM analysis for TEC Participants FMPA and JEA, state the following: "My understanding and the reason that no further analysis was performed was...the unique customer bases of Reedy Creek." [T.1171-72] Witness Kushner confirmed that he did not perform any

[10] It is undisputed that neither the DSM analysis that Witness Kushner performed (assessing 180 DSM measures for FMPA and JEA) nor the analysis performed by COT included any assessment of DSM for RCID.

analysis of RCID's DS< programs the programs implemented by Disney, or the programs implemented by any of RCID's non-Disney customers. [T.1172] In his testimony, Witness Guarriello testified that RCID plans "to consider any DSM and conservation programs in the future," indicating that RCID and its customers will continually evaluate opportunities fir energy conservation." [ T.715] However, this testimony did not indicate that RCID had affirmatively evaluated the potential for additional DSM or conservation measures in connection with this Application, nor did it provide any details whatsoever regarding the nature or scope of future consideration of DSM. The Applicants' off-hand dismissal of any obligation for RCID to specifically evaluate existing and potential DSM effectively renders meaningless the §403.519 requirement to consider conservation measures that might mitigate the need for the proposed plant.

Notably, while the Application indicated the Walt Disney World has a strong relationship with U.S. EPA, and participants in EPA's Energy Star Building program, there is no indication in the record that RCID's other commercial customers also participate in the EPA program. At hearing, Witness Guarriello did indicate that RCID provides energy audits for commercial hotels to assist then in making DSM-related decisions; however, it is far from clear that the customers have implemented DSM measure to the same degree as Disney. [T.726-27][11]

RCID itself only implements two DSM measures of its own - thermal storage program and participation in the Green Lights Program. [Ex. 58, D.7-1; T.715] However, RCID did not specifically evaluate the existing effectiveness of the DSM measures that it implements at its own facilities, or specifically evaluate the possibility of adopting additional conservation or efficiency measures.

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[11] With respect to energy efficiency measures for both Disney and RCID's non-Disney customers, such decisions are made on the basis of the cost-effectiveness determinations made by the customers themselves. [T.724-45, 727] Moreover, it appears that they make these decisions based on an analysis of cost and saving to the customer, not based on a rate impact measure. [T.727] Thus, RCID's assessment of DSM for this proceeding should have evaluated potential for DSM measure on the same basis-to reflect the types of measure that its customers would find attractive.

In the end, RCID'd assessment of DSM in connection with this need determination application is woefully inadequate. It consists of little more than a general description of existing actions being taken independently by its customers (without any analysis) and conclusory statements about the adequacy of these measures and the general commitment of RCID and its customers to continue evaluating opportunities as they see fit.

As with JEA and FMPA, RCID did not perform an analysis similar to the one that COT conducted, to determine what technical, economic, and achievable DSM potential exists. This kind of analysis is rational, reasonable, and necessary, to demonstrate that DSM options are not available to reduce, defer, or mitigate the need for new capacity. Because RCID did not perform an adequate DSM analysis, it has not met statutory obligations in connection with this proceeding.

<u>TALLAHASSEE</u>: Of all of the TEC Applicants only COT performed an analysis of DSM optins that provides a meaningful assessment of what options are technically feasible, cost-effective and achievable. This analysis is included in the record as Exhibit 106, Assessment of Maximum DSM Potential for the City of Tallahassee. This analysis appropriately sought to answer the question for COT: "What is the achievable DSM potential."

Exhibit 106 describes a meta-analysis performed by Navigant Consulting, Inc., that synthesized the results of multiple existing studies to determine the maximum energy and load reduction that COT could achieve, through cost-effective DSM measures, by the year 2025. [Ex. 106, 1] The report specifically evaluated technical potential (maximum savings regardless of cost); economic potential (maximum savings from cost-effective measures); and achievable potential (maximum savings from cost-effective measures considering mitigating factors that may reduce measure effectiveness). [Ex. 106, 9-12]

As reflected in the Applicants' Response to NRDC's Second Set of Interrogatories, COT's analysis looked first at the levelized cost of various DSM measures. [Ex. 105, 26-31] According to testimony at hearing, this was the first step in the City's DSM analysis. [T. 1169] COT then screened each measure using a cost-effectiveness test that was based on the busbar cost of each measure compared to comparable supply-side resources, where the costs of the supply-side resources and DSM measures were computed on a levelized basis over the life of the DSM measure. [Ex. 20, E.7-5] In COT's analysis, the levelized costs for the DSM measures were lower than or the same as the relevant supply-side options for almost all DSM measures screened. [Ex. 20, E.7-5] COT then used these measures to develop an overall DSM portfolio.[12]

Ultimately, COT's analysis of DSM opportunities allowed it to identify total demand reductions of 161 MW (summer) and 147 MW (winter) by 2025. [Ex. 58, Table E.7-2] Additionally, it allowed the City to defer additional capacity need until 2016.[13] [T. 1198] Clearly, COT's evaluation of DSM potential was rational, reasonable and appropriate, and demonstrated cost-effective measures that are reasonably available to the City.

Nowhere in the record of this proceeding is there evidence demonstrating that the measures identified by COT, or similar such measures, are not available to the other TEC participants at a similar level of cost-effectiveness. The fact that none of these measures would pass the Rate Impact Test (RIM test) does not establish that they are not cost-effective. Similarly, the fact that the DSM measures evaluated for other TEC participants did not pass the RIM does not establish that those measures are not cost-effective. The other TEC participants can and must conduct a more robust assessment of available DSM; if they do so the record suggests they too will be able to identify measures, similar to those

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[12] Additional details of COT's DSM analysis and the resulting portfolio are presented in Exhibit 20 at pages E.7-5 through 7-15.

[13] One outcome of this analysis is a demonstration that COT does not need additional capacity in the time frame contemplated for TEC (2012) - rather their need for additional capacity has been deferred by DSM to 2016. The argument made at hearing that COT needs additional capacity in 2012 despite the benefits attributable to DSM because capacity from TEC will be cheaper than COT's otherwise available capacity resources is simply untenable. [T. 1199] If the Commission were to accept this rationale, it would make a mockery of the need determination process, and demonstrating need would become nothing more than an exercise of showing that proposed capacity would be cheaper than some other element of a utility's existing capacity resources even where existing resources are entirely adequate to meet demand.

identified by COT, that will be available at similar levels of cost-effectiveness.

CONCLUSION:

Based on the arguments presented above, it is clear that the record in this proceeding cannot support a finding that DSM has been adequately considered by each TEC Applicant. Only COT has performed a robust analysis that specifically and appropriately compares the cost of DSM measures to the benefits that such measures will provide. FMPA and JEA rely upon analyses that allow them to inappropriately reject cost-effective measures. Moreover, RCID conducted no meaningful assessment of DSM whatsoever. For these reasons, with the exception of the City of Tallahassee, the Applicants have failed to adequately consider conservation measures as required by Florida law.

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

**Position:** **No. While the PRISM model appears to be an excellent tool for forecasting mercury, SO2, Nox and $CO_2$ emission allowance costs and associated fuel costs, the assumptions which form the parameters of the $CO_2$ emission allowance cost study in this case are specious. Allowing $CO_2$ 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" $CO_2$ emission multiclient study, which does accurately reflect the provisions of the McCain-Liberman bill, would have given a more accurate forecast of a $CO_2$ regulated environment. These results are consistent with Dr. Lashof's testimony of reasonable $CO_2$ emission allowance costs and could have been used to produce a $CO_2$ regulated sensitivity study that truly evaluated the impact of $CO_2$ regulation. Without a valid $CO_2$ sensitivity study and associated IRP, the Applicants have not demonstrated that TEC is the most cost-effective alternative available.**

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As discussed in Issue 9, the Applicants have taken the position in this docket that because there are no federal or state $CO_2$ regulations at this time, the impacts of possible $CO_2$ regulation during the 40 year operational life of TEC are too speculative and should be ignored. [T. 1248, 1270] In an abundance of caution, however, the Applicants have included a $CO_2$ sensitivity analysis which uses the forecasts for fuel, SO2, NOx and $CO_2$ emission allowances under a $CO_2$ regulated environment prepared by Witness Preston. [Ex. 40; Ex. 3, Revised Tables B-6-18, C.6-18, D.6-10 and E.6-18] Not surprisingly, these individual Applicant sensitivity studies show that the construction of TEC in 2012 is still the most cost-effective alternative for each individual Applicant. [Ex. 3, Revised Tables B-6-18, C.6-18, D.6-10 and E.6-18]

The PRISM model developed under Witness Preston's supervision is an extremely complex model with literally thousands of data inputs. The PRISM linear programming model literally recreates the electric grid in the United States and Canada, complete with transmission constraints and specific operating parameters for each industrial and electric utility power plant over 25 MW, and produces a forecast for various types of coal, pet coke, SO2, mercury, $CO_2$ and NOx emission allowances. [T.1028-32] NRDC has no quarrel with the PRISM model. NRDC does, however, have serious problems with the assumptions used in the development of the $CO_2$ forecasts which were ultimately used in the $CO_2$ regulated sensitivity studies conducted by the Applicants.

First, Witness Preston testified that he reviewed the provisions of the McCain-Liberman Climate Stewardship Act of 2005 and modified them where necessary to reflect what he believed "could possibly happen or plausibly happen." [T. 1033-4, 1038-9] The McCain-Liberman bill caps $CO_2$ emissions at 2000 levels from 2010 until 2015 and then reduces them to1990 levels beyond 2015. [Ex. 79, p.13] Witness Preston capped $CO_2$ emissions at 2000 levels plus 10%, or approximately 2.7 billion tons, starting in 2010. [T. 1035] For each year after 2010 the $CO_2$ cap increases by 0.5% per year. [T. 1036] Thus, a major difference from the McCain-Liberman bill, and virtually every other proposed bill, is that $CO_2$ emissions will be allowed to increase over time and not be capped or reduced. [Ex. 79, p. 13; T. 1036] A reduction in the total amount of $CO_2$ allowances available, the equivalent of a reduction in $CO_2$ emissions, was also an assumption used by JEA in its internal analysis of the impact of $CO_2$ regulation. [T. 679] Witness Preston also assumed that $CO_2$ allowances granted to the different $CO_2$ emitting sectors regulated (industrial, transportation, commercial and electric power) would be fungible so that the PRISM model could allow power plant emissions to fluctuate up to the number of allowances available for all regulated domestic sectors. [T. 1037-8] The PRISM model could also use international $CO_2$ allowances to satisfy emission caps, i.e., allowances traded on the European Union market. [T. 1038; Ex.1, Preston Depo. at 49] The net effect of these assumptions is that there would be a reduction in $CO_2$ emissions by the nonelectric sectors. [T. 1055] These assumptions regarding the availability of emission allowances would tend to maximize the $CO_2$ allowances available under the model for the entire study period.

Second, Witness Preston capped the annual demand growth rate, as measured in net energy for load, in all control areas at 1%. [T. 1041] All of the Applicants have testified that each of their systems has had annual demand growth rates of 1% or greater over the last 5 years, ranging from 8% to 1.5%.[14] With the exception of RCID, all of the Applicants have forecasted annual demand growth rates of greater than 1% over the study period.[15] The forecasted growth rates range from 2.5% to 1.7%. Witness Rollins, who has reviewed Florida's statewide annual demand growth rates for the last 29 years, confirms that Florida's statewide historic demand growth rate over the last 10 years has been approximately 2%. [T. 350-1] To assume that Florida, or any of the Applicants, under a $CO_2$ regulation scenario would reduce growth rates by one-half is simply unreasonable. Further, it would assume that RCID, who is only projecting a 0.5% annual demand growth rate for the entire study period, would experience no demand growth at all.

Witness Preston testified that the failure of Florida to reduce its annual electric demand to 1% or less would have little effect on the study results. Presumably this is because Florida's electric demand would be a very small percentage of the total electric demand modeled by the study. [T. 1041-2] However, if all historically high electric demand growth states (California, Arizona ) are capped at 1%, the results of the study are affected. Modeling higher growth rates for electric demand would tend to increase the cost of $CO_2$ emission allowances.

Third, Witness Preston assumed that 12 nuclear power plants would come on line between the

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[14] JEA's average annual growth rate over the last 5 years is approximately 2.5%; over the last 10 years has been greater than 1%. [T. 683-4] RCID's average annual growth rate has been 8% over the last 8 years. [T. 722-3] Tallahassee's average annual demand growth rate has been 1.5 to 2% over the last five years; and approximately 2% over the last 10 years.

[15] The base case forecast of demand and energy for FMPA shows net energy for load (NEL) average annual growth rates of 2.5 percent from 2007 until 2009 and 2.0 from 2010 through 2024. [Ex. 58, p.B.3-7, Table B.3-3]. The base case forecast of demand and energy for JEA shows net energy for load (NEL) average annual growth rates of 2.2 percent from 2006 until 2024. [Ex. 17, p.C.3-8, Table C.3-5, T. 654]. The base case forecast of demand and energy for COT shows net energy for load (NEL) average annual growth rates of 1.7 percent from 2007 until 2025. [Ex. 20, p..E.3-5, Table E.3-3]. RCID's forecasted base energy requirement is initially 1,259 GWh in 2006 and grows to 1,395 GWh in 2025, an average annual increase during the study period of 0.5% . [Ex. 18, p.D.3-2, Table D.3-1; T. 713]

years of 2016 and 2020. [T. 1039; Ex. 3, Preston Depo., p. 76] This assumption was based on permit applications received by the Nuclear Regulatory Commission. [Ex. 3, Preston Depo.,p.49] No new nuclear power plants have constructed in the United States in the last 20 years. [T. 1074] No new nuclear power plants have been constructed in Florida in the last ten years, although there may have been some small capacity expansions to existing units. [T. 351-2] Witness Klausner, the Applicants' expert on supply side technologies, has classified the new generation of nuclear power plants as "emerging technology" which he would not classify as an established technology with demonstrated reliability before 2020. [T. 1091-2] Further, Witness Klausner testified that having 12 nuclear power plants in service by 2020 is only possible if all of the regulatory approvals are actually received in the next three to four years. [T. 1092-4] The difficulty of permitting nuclear units, the disposal of nuclear waste, the supply of nuclear fuel, the availability of nuclear reactors and associated equipment all act as constraints on the actual construction of nuclear power plants. [T. 1039-40] Given these constraints on the construction of nuclear power plants, the assumption that 12 nuclear units will actually be operational by 2020 is implausible.

Fourth, Witness Preston assumed that 12% of the energy generated would be provided by renewables (sources other than nuclear that did not produce greenhouse gases) and that renewable energy resources would grow at 0.5% per year until it reached a level of 20%. [T. 1020-21] At this time approximately 10% of the nation's generation comes from these sources. [T. 1021] Florida does not currently have a renewable standard. [T. 1043]

Fifth, Witness Preston's model assumes that the volume of natural gas will dramatically increase in between the years 2016 and 2017 which will partially account for the dramatic decrease in the $CO_2$ emission allowance cost from $8.89 in 2016 to $2.43 the next year. [T. 1044] With an increase in the volume of natural gas, all other things being equal, natural gas prices should decline. However, none of the forecasts used in this case, not even in Witness Preston's exhibits, showed natural gas prices declining in price in 2016 or 2017. [Ex. 37-40; Ex. 27-30; T. 973-4]

Finally, Witness Preston himself prepared two "full blown" $CO_2$ emission allowance studies one of which was a "multiclient" study based on the actual assumptions of McCain-Liberman bill, i.e., a cap and then reduction in $CO_2$ emissions. [T. 1045; Ex. 79 at p. 13] A multiclient study is one that Hill & Associates prepares to sell to its customers based on its assessment of the impact of particular environmental regulations on the operating cost of their electric systems or on the cost of fuels and wholesale electric power. [Ex. 3, Preston Depo., p. 7-8] This $CO_2$ emission allowance study, which would have used similar cap and reduction assumptions to the $CO_2$ emission allowance study done internally by JEA, produced $CO_2$ emission allowance costs which were at least 100% greater than those in Ex. 40. [T. 676-78, 1046] The average $CO_2$ emission allowance cost in Witness Preston's $CO_2$ sensitivity study is $7.01/ton.[Ex. 40] Assuming that a 100% increase, the "multiclient" $CO_2$ emission allowance study would produce average $CO_2$ emission allowances costs of $14.02/ton, a number that falls within the $8.00 to $40/ton range testified to by Dr. Lashof. [T. 861] The Applicants' $CO_2$ emission allowances are higher from 2011 through 2017 than Synapse Energy Economics' low case forecast and lower than their forecast from 2017 through 2030. [Ex. 40, 112; T. 1195] The Applicants' $CO_2$ emission allowances are lower than Synapse Energy Economics mid and high forecasts throughout the entire study period. [T.1195]

Witness Preston dismisses his own company's multiclient study as having been done to "show that McCain-Liberman as proposed would wreck the U.S. economy." [T. 1045] While it may be Witness Preston's opinion that the implementation of the provisions to cap and reduce $CO_2$ emissions in the McCain-Liberman bill would "wreck the U.S. economy", it seems highly unlikely that Hill & Associates would develop a forecast for sale to its customers with that stated goal. It seems much more probable that Hill & Associates simply prepared a forecast which accurately modeled all of the provisions of the McCain-Liberman bill as written. That's the type of forecast one could sell to many customers, not one in which any particular result was preordained. The type of forecast that achieves a particular goal is one prepared for a specific client to support a client's position as the $CO_2$ sensitivity study prepared here, Ex. 40. The true McCain-Liberman forecast, the multiclient forecast, was rejected by the Applicants because the $CO_2$ emission allowance costs did not support the result desired - a cost-effective TEC.

In sum, the assumptions modeled by Witness Preston in his $CO_2$ emission allowance study are so specious that the $CO_2$ regulation sensitivity studies using that data cannot be relied upon by the Commission to support the Applicants' assertion that under a $CO_2$ regulation scenario TEC remains the most cost-effective alternative to meet the Applicants' individual or collective needs.

**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, $NO_x$, $SO_2$ and particulate emissions?**

**Position:** **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.**

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As discussed in Issue 9 above, the forecasted cost of the various types of coal, natural gas and diesel developed by Witness Preston reflects the influence of the price of mercury, $NO_x$ and $SO_2$ (and in the $CO_2$ sensitivity study, $CO_2$) emission allowances. [T. 1031; Ex. 37-40] Witness Myers added the cost of transportation to the forecasted commodity costs developed by Witness Preston to arrive at the delivered cost for the various fuels used in the IRP modeling by Witness Kushner. [T. 972; Ex. 27-30] This adjusted price was used by Witness Kushner in his IRP analyses. [T. 973] All of the assumptions used by Witness Preston in the development of his commodity prices for the various types of coal were based on federal emission control standards for mercury, NO2 and SO2, not Florida emission control standards for those substances. [T. 346, 1031; Ex.1, Preston Depo. at 32] Florida has proposed its own state implementation plan for the Clean Air Interstate Rule (CAIR ), which deviates from the federal standards. This state implementation plan has been challenged. [T. 346] Because of this challenge, DEP has not submitted its state implementation plan to the federal Environmental Protection Agency (EPA) for approval. [T. 347] Thus, no final Florida implementation plan for $NO_2$ and $SO_2$ substances currently exists. [T. 347 ] Further, Florida is likewise required to develop a state implementation plan for the Clean Air Mercury Rule (CAMR). Florida has done so. However, Florida's proposed implementation of CAMR is substantially different that the federal proposal, e.g., it will withhold 25% of the available mercury allowances for 6 years between 2012 and 2017 and allocate a certain number of allowances each year for new units. [T.326] DEP has released an administrative order quantifying the initial mercury allowances available to substantially affected persons under the CAMR program. [T.348-9; Ex. 1, Staff's Second Set of Interrogatories No. 63] This administrative order is a preliminary allocation subject to challenge under Chapter 120, F.S., by all substantially affected persons. For that reason it is also not final. Even if Florida's CAMR implementation plan were final, Witness Preston did not make any adjustments to his PRISM model to take Florida's specific CAMR implementation criteria into account. [Ex.1, Preston Depo. at 30] 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.

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

**Position:** **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.**

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On October 5, 2003 the Taylor County Commission by resolution requested that TEC request federal funding for an IGCC plant. [T. 406-7] Witness Lawson testified that JEA representatives on behalf of TEC had made verbal inquiries to the Department of Energy as well as members of Congress about available federal funding under the Clean Coal Power Initiative and Clean Air Coal Program. [T. 407-8; Ex. 8] No formal written request was ever made by the Applicants to DOE for such funding nor does DOE have a record of any communications at all with the Applicants. [T. 408; Ex. 102]

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

**Position:** **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.**

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The Phase II-B Development Agreement, properly executed by all the Applicants with the appropriate authorization of their respective Boards, controls the development of the TEC through the receipt of all operating permits. [T. 422] Pursuant to the Phase II-B Agreement any participant can reduce or relinquish his share of TEC without the permission of other participants if another participant is willing to take it and to a third party with the written consent of the other participants. [T. 423-25] Each participant has the "right of first refusal" for any capacity that a participant wishes to relinquish. [T. 424-5]

Once all permits are received, including Site Certification from the Power Plant Siting Board, capital and operating costs based on the final permit conditions and all other applicable available information will be recalculated. [Ex. 1, Phase II-B Development Agreement at p.62] At that time all Applicants will be given the opportunity to make a "go, no-go" decision. [T. 425] All contractual responsibilities under the Phase II-B Agreement for each Applicant are satisfied once all permits have been secured. [T. 425] After that date, if the Applicants chose to go forward with participation in the project, a Participation Agreement for post-Phase II-B activities will be executed by the remaining parties. [T. 425-6; Ex. 1, Phase II-B Development Agreement at p. 62] In addition to the clear terms and conditions of the Phase II-B Agreement discussed above, it is clear that Tallahassee has not made its final decision to participate in TEC because its City Commission has not approved an IRP which includes TEC as of this date. [T. 764]

Once TEC is constructed each participant will have the ability to sell his share of TEC capacity to the Florida wholesale market. [T. 426] It is anticipated that bulk wholesale power sales will be made from TEC to the Florida wholesale market once constructed. [T. 427-8] Whether each individual participant or TEC collectively will make bulk wholesale power sales from TEC has not yet decided but will be worked out in subsequent contracts. [T. 427] Witnesses May, Gilbert, Guarriello and Brinkworth all confirmed that there is virtually no baseload electric capacity and energy currently available in the Florida wholesale market. [T.490-91, 679-81, 766-7, 723-4] All these witnesses also confirmed that any such baseload energy and capacity from TEC could be sold at a premium price. [*Id.*] Indeed, Witness Brinkworth testified that Tallahassee had up to 100 MW of capacity and energy to sell from 2012 until 2016, should Tallahassee decide to participate in TEC. [T. 767] NRDC would suggest that at least for Tallahassee, and perhaps for other Applicants to a lesser degree, the decision to move forward with participation in TEC will be driven in part by its ability to receive revenue from TEC wholesale electric sales rather than an actual need for TEC energy or capacity on its own system.

For this reason, if the Commission should decide to grant the TEC need determination, it should be conditioned upon the actual participants in TEC, whomever they maybe, reaffirming their individual need for their share of TEC's capacity. The Commission has the ability to issue conditional need determinations and should do so here. *In re: Petition of Florida Power and Light Company to determine need for electrical power plant - Martin expansion project*, 90 FPSC 6:268, 282 (1990)("Pursuant to Section 403.519, Florida Statutes, the Commission has the inherent authority to place conditions on need determinations supported by the record developed in the proceeding."); *In re: Petition of Seminole Electric Cooperative, Inc., TECO Power Services Corporation and Tampa Electric Company for a* *determination of need for proposed electric power plant,* 89 FPSC 12:262 (1989) If the Commission does not do this, it runs the very real risk of granting a need determination for what is essentially a wholesale merchant power plant which satisfies statewide, not individual utility, capacity and energy needs. The Commission, although asked repeatedly to do, has steadfastly refused to issue such a generic need determination to meet statewide energy and capacity needs . *In re: Petition for determination of need for electrical power plant (Amelia Island Cogeneration Facility) by Nassau Power Corporation*, 92 FPSC 2:814, 827 (1992); *In re: Petition of Nassau Power Corporation to determine need for electrical power plant (Okeechobee County Cogeneration Facility); Petition of Ark Energy, Inc. and CSW Development-I, Inc. for determination of need for electric power plant to be located in Okeechobee County, Florida; Petition of Ark Energy, Inc. and CSW Development-I Inc. for approval of contract for the sale of capacity and energy to Florida Power & Light Company; Petition of Nassau Power Corporation for approval of contract for the sale of capacity an energy to Florida Power & Light Company,* 92 FPSC 10:643 (1992). It should not do so now.

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

**Position:** **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.**

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

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

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## CERTIFICATE OF SERVICE

**I HEREBY CERTIFY** that a true and correct copy of the foregoing has been provided by electronic mail as listed and U.S. Mail, this 24th day of January, 2007 to the following:

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