BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 060635-EU

In the Matter of

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

_____/

VOLUME 6

Pages 514 through 642

ELECTRONIC VERSIONS OF THIS TRANSCRIPT ARE A CONVENIENCE COPY ONLY AND ARE NOT THE OFFICIAL TRANSCRIPT OF THE HEARING, THE .PDF VERSION INCLUDES PREFILED TESTIMONY.

PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN LISA POLAK EDGAR COMMISSIONER ISILIO ARRIAGA COMMISSIONER MATTHEW M. CARTER, II COMMISSIONER KATRINA J. TEW
DATE:	Thursday, January 11, 2007
TIME:	Commenced at 9:30 a.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	MARY ALLEN NEEL, RPR, FPR
APPEARANCES:	(As heretofore noted.)

I N D E X

WITNESSES

WITNESSES CONTINUED

EXHIBITS

NUMBER		ID.	ADMTD.
9			532
10			532
11			532
12			532
13			532
14	JPN-1		533
15	TEC-1		533
32	TRB-1		536
33	TRB-2		536
34	TRB-3		536
35	TEC-1		536
43	JH-1		536

EXHIBITS CONTINUED

NUMBER		ID.	ADMTD.
44	JH-2		536
45	JH-3		536
46	PN-1		537
47	PN-2		537
48	TEC-1		537
49	RJP-1		537
50	TEC-1		537
51	RJP-1R		537
59	SMF-1		641
60	DB-3		535
75	DD-1		536
76	DD-2		536
77	DD-3		536
78	DD-4		536
79	DD-5		536
80	DD-6		536
81	DD-7		536
103			532

P R O C E E D I N G S

(Transcript follows in sequence from Volume 2.)

CHAIRMAN EDGAR: Okay. We will go back on the record. Thank you all. I know it's been a long day.

My under -- I'm sorry. That's okay. My understanding -- right before we went on break, I said let's talk about schedules, and I understand that some of those procedural discussions have occurred -- is that we are good to go tomorrow, that we may take a witness or two, or maybe even three if something else comes up, out of order, which, of course, we will work through together, but as I said, I'm certainly amenable to.

And we will just go for a little while longer today and then break for the evening, come back fresh tomorrow at 9:30, and push through as hard as we can. I have a commitment at 1:00 that I do need to still honor, so I'm going to, as we have the last two days, aim to take kind of a late lunch break and work it that way. If there are scheduling issues that come up, work with our staff, and we'll see what we can do.

Any questions or concerns?

MS. BROWNLESS: Just a question. Will we have a full day of hearing tomorrow, Your Honor?

CHAIRMAN EDGAR: That is my intention.

MS. BROWNLESS: Thank you.

CHAIRMAN EDGAR: Okay. Mr. Jacobs.

MR. JACOBS: Thank you, Madam Chair.

CONTINUED CROSS-EXAMINATION

BY MR. JACOBS:

Q. Mr. May, just a few more questions, and I think we'll be done.

We were talking just prior to our break about the idea that there are transmission costs, and you clarified for me, and I thank you for that, that while there is a lump sum charge to FMPA, you really are going to kind of allocate that at the same rate that you do for your normal transmission charges under the contract that you have. Is that correct?

A. No, that is not correct.

Q. Okay. Why don't you explain to me then how your transmission charges that are associated with TEC are going to be consumed?

A. Okay. The transmission charges, the 35 million or 39 million, or whatever the number ends up being, will be financed as part of the project. We will -- if those charges -- we have the -- there's a possibility of those charges either being designated by Progress Energy as direct costs, which would be our costs, or network upgrades.

Indications are at this point that they'll be classified as network upgrades. Being network upgrades means that they would belong to Progress Energy, and under our network service payment, which we pay both Progress Energy and Florida Power & Light for access to their transmission grid through a tariff based on our demand, we would continue to pay that tariff, but on our monthly bill from Progress Energy, we would receive a portion of that $39 million back.

And so over a period as short as five years, we could -- or even shorter if Progress Energy wants to allocate it back, if we have enough transmission charges, we could receive the cost of that back, which, of course, we would pass on to our customers.

Q. I see. Thank you. I understand that now.

Individual customers who take service from an FMPA member then, will they see -- they won't see a difference in any transmission charge in their billing per se?

A. The individual cus -- our individual members pay for transmission charges through our demand rate.

Q. Okay. That then I guess moots my next line of questioning, but let me ask you this. In your deposition, I believe you stated that one of the ways you promote DSM is by sending price signals to your

members. Based on your response here, we would assume that that's only through fuel charges that those price signals are transmitted?

A. Well, we send price signals to our customers through their bill for demand charges and energy charges, which is adjusted on a monthly basis.

Q. Okay. My real focus is, then it would not be the case that a customer would want to respond -- would want to look at some way of avoiding transmission charges, because they probably wouldn't see those charges -- any difference in those charges committed through a price signal?

A. Avoid transmission charges?

Q. Yes.

A. I don't understand.

Q. It sounds like a customer would not receive information about transmission through its demand charges, as I've understood your explanation here.

A. By customer, do you mean a retail customer or a member?

Q. No, a member.

A. Because we're cost based, any changes in our transmission costs are reflected in the demand rate.

Q. I understand. Let me move on.

You were involved in the planning and

implementation of the Treasure Coast facility, were you not?

A. Yes.

Q. And that is a combined cycle natural gas plant; is that correct?

A. That's correct.

Q. Were you involved in any sensitivity analysis done for Treasure Coast with regard to its alternative being a coal plant?

A. No, we did not evaluate coal for -- as an alternative for Treasure Coast in 2008.

Q. Okay. Have you done any analysis with regard to your expansion needs that are being incorporated into Taylor Energy Center? Have you done any analysis of making Treasure Coast the site of those expansion plans?

A. I don't quite understand your question.

Q. For the capacity needs that are being met by your ownership in Taylor, Taylor Energy Center, have you done an analysis of putting a unit at Treasure Coast to meet those needs?

A. Yes, we have.

Q. And what was the result of that analysis?

A. Well, compared to Taylor Energy Center in 2012, the coal plant was significantly less costly than the Taylor -- than a second combined cycle unit

anywhere.

Q. Okay. But Treasure Coast in 2008 was less expensive? The gas option in 2008 was less expensive?

A. It was not feasible for us to build a coal plant in the three-year time frame we had to get Treasure Coast built for 2008.

Q. I see. My question, though, was -- oh, I'm sorry. You answered earlier you really didn't do an analysis of gas versus coal in the Treasure Coast analysis.

Was there analysis done for Taylor Energy Center -- let me strike that for one moment. At the site for Treasure Coast, is there an opportunity -- facilitieswise and infrastructurewise, can there be an additional unit built there?

A. That site is permitted -- yes.

Q. Okay.

A. The simple answer is yes.

Q. Would it have been a reasonable analysis to look at your site for Treasure Coast as a brownfield opportunity to build the whole facility that is now planned for Taylor? Would that have been an option, as a brownfield option at your site for Treasure Coast?

A. For FMPA, we actually did the analysis of not taking 300 megawatts of Taylor Energy Center and

building a combined cycle unit. It was more costly.

Q. I see. In 2008? I'm sorry, in 2012?

A. In 2012, it was more costly. And further, it would be located on Florida Power & Light's transmission network, and we needed something, some type of capacity connected to Progress Energy's network to help meet our load that's connected to Progress Energy.

Q. Are you aware of the -- this may be out of your purview. If so, please just let me know. But are you aware of the all-gas analysis that was done by the City of Tallahassee?

A. I'm vaguely aware. I'm not familiar with it.

Q. In that analysis, the gas, the all-gas option was the base case analysis; is that correct?

A. I'm not familiar with it. I can't comment on that analysis.

MR. JACOBS: Okay. Just one moment. I think I may be done.

Thank you.

CHAIRMAN EDGAR: Are there questions from staff?

MS. FLEMING: Yes, and we'll be very brief.

CROSS-EXAMINATION

BY MS. FLEMING:

Q. Good afternoon, Mr. May.

A. Hi.

Q. In your deposition, you stated that FMPA has an 80-megawatt purchased power agreement with Southern Company set to expire in 2013; correct?

A. Correct, yes.

Q. And you further testified that FMPA hasn't made a decision as of yet whether to extend that contract; correct?

A. Yes, that's correct.

Q. If FMPA chooses to extend this contract, how will it affect FMPA's need for capacity in Taylor Energy?

A. It would not affect it at all, because our need for Taylor Energy for capacity in the time frame 2012 and 2013 far exceeds the 80 megawatts that we have available through that contract.

Q. What is FMPA doing to review the availability of additional cost-effective purchased power opportunities on a continuing basis?

A. Our planning process is to evaluate over 20 years what type of capacity that we need to meet, to have a mix that fits our load profile and minimizes our costs with respect to fuel costs and timing of those generating units.

At the point that we see that, based on lead

times, we need to pursue a certain type of capacity, we will issue a request for proposals for that type of capacity. For instance, for the Treasure Coast, we issued a request for proposals for based intermediate capacity connected to FPL or Progress Energy. And knowing what kind of capacity we needed and the timing of that capacity, we evaluated proposals compared to a self-build option. We did the same thing for Taylor Energy Center and for the peaking purchase that we recently executed with Southern Company to purchase capacity through Southern Company.

So that's generally our process of going to the market to find out if there is from the market -- whether they're building it or capacity exists that we can purchase from existing capacity to eliminate our need to build something.

Q. We've heard that FMPA has approval for participation in the Taylor Energy Center through the permitting process, but not yet as to the construction phase. Does that mean that the applicants will have another chance to decide if they want to proceed with participation in the Taylor Energy Center at the construction phase?

A. Yes.

Q. And at that point, when the applicants make a

determination whether they want to proceed, what factors will FMPA review in order to determine if it's still in the members' best interest to participate in this Taylor Energy Center?

A. Because we do an integrated resource plan at this point about every two years, we evaluate with the most current information that we have all of our options going forward, including the Taylor Energy Center. So therefore, we would be continuing to do that evaluation.

At this point, the savings that we receive from the Taylor Energy Center are substantially greater than the next best option that we have looked at as a self-build option, and even greater than that, from a purchased power perspective based on proposals we've received. We would at that point in time evaluate whether it's still cost-effective for FMPA to pursue this coal unit and make a decision at that point.

Q. Would you agree that it is prudent for utilities to continuously evaluate whether participating in a particular generation plant continues to be cost-effective?

A. Yes, I think we should.

Q. Now, earlier there was some discussion regarding a 2006 rate impact analysis, but we didn't really get into the details of that. What were the

results of that rate impact analysis?

A. The results of that rate impact analysis in all cases that we evaluated were that over the long period of time -- and long period of time at that point was 20 years from 2004 or 2006. From the period of time that the coal unit went in service, the rates to FMPA customers were lower than the next best option. And even in the 2006 case, that was reconfirmed that that was the same conclusion, that the rates were lower than any of the other options.

And we evaluated quite a few options. In the 2004 case, we started with nothing but combustion turbines, just gas turbines, and said, "Okay. If that's all we could build, what is our cost to our customers?" We refined that to add more efficient units, combined cycle units, up to a level that was reasonable for the mix that we needed for our load and confirmed that, yes, adding combined cycle units reduces our rates from nothing -- from just adding combustion turbines.

The next thing we did was evaluate, in a feasible range of achieving it, adding coal. Of course, the Taylor Energy Center was that option. And it further reduced our rates. So we looked at a great deal of options, and in both 2004 and 2006, it was confirmed that adding the coal unit reduced our rates.

MS. FLEMING: Okay. Thank you. No further questions.

CHAIRMAN EDGAR: Ms. Raepple?

MS. RAEPPLE: Thank you.

REDIRECT EXAMINATION

BY MS. RAEPPLE:

Q. Mr. May, are FMPA's members cities?

A. Yes.

Q. Do those cities' governing bodies make their own independent decisions on what DSM measures are appropriate to be implemented within their area?

A. Yes, they do.

Q. To determine if there are any DSM measures available that might mitigate the need, that might mitigate FMPA's need for the capacity to be provided by the Taylor Energy Center, is it essential that FMPA's total load be considered in the aggregate?

A. Yes, because those DSM measures would be based on our adjustments to the total load that FMPA has, and therefore a reduction in the peak demand for FMPA as opposed to the individual cities.

Q. Are the DSM measures currently implemented by FMPA's members reflected in FMPA's load forecasts?

A. Yes, they are, because we use -- our load forecasts are based on two predominant measures. One

is, we take their historical loads, individual cities' historical loads on an hourly basis, as well as the econometric data, population, average income, things of that nature, for each of the 15 cities to predict how those cities would grow. So to the extent that cities implement DSM programs, it's reflected in the actual load piece that's implemented, that's used.

Q. In questioning from Mr. Jacobs, you talked about ESCOs. What's an ESCO?

A. ESCO is energy services company, which is a consulting company to analyze commercial and industrial energy use.

Q. And are those commercial and industrial customers that the ESCO works with for-profit companies?

A. Yes, they are.

Q. And does the ESCO show them how they could save money on their utility bill?

A. Yes.

Q. Does any utility have the ability to require customers to implement cost-saving measures to lower their utility bill?

A. Not to my knowledge. It's up to the individual customer to make those decisions and implement measures that could save money and reduce their energy consumption.

Q. And that is the information you provide to them?

A. Well, that's the information that the ESCO provides.

Q. That the ESCO provides? And finally, in questions that Mr. Jacobs posed, you responded, talking about sending price signals through demand and energy charges. Could you just define for us the difference between demand and energy charges, please?

A. We have certain costs that are costs that we will incur whether there's a single megawatt-hour or kilowatt-hour of energy consumed, the cost to build a power plant, the cost of offices, the cost of transmission. Those costs are rolled together, and based on our total demand, our peak demand, our coincident peak, we calculate what the demand rate would be to recover those costs, and that's the demand rate that's charged to the cities.

Our variable cost, which is based on fuel cost and therefore the efficiency of the generating units, our operating and maintenance cost, which varies, there again, based on how the units are operating, how much they're operating, we predict those total costs and the total amount of energy to be consumed by the cities and calculate an average energy rate to recover those costs,

and so that's the energy cost that is charged to our individual cities.

Q. So is the difference between demand and energy basically the difference between fixed and variable costs?

A. Very much, yes.

MS. RAEPPLE: Thank you. I have nothing further.

CHAIRMAN EDGAR: Let's take up the exhibits.

MS. RAEPPLE: Yes. At this time, I would move into the record Exhibits 9, 10, 11, 12, and 13.

CHAIRMAN EDGAR: Exhibits 9, 10, 11, 12, and 13 will be entered into the record.

(Exhibits Number 9, 10, 11, 12, and 13 were admitted into evidence.)

CHAIRMAN EDGAR: And then, Ms. Brownless, Exhibit --

MS. BROWNLESS: Madam Chair, we would also like to move Exhibit 103.

CHAIRMAN EDGAR: Any objection?

MS. RAEPPLE: No objection.

CHAIRMAN EDGAR: No objection. Okay. Show Exhibit 103 entered into the record.

(Exhibit Number 103 was admitted into evidence.)

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

Okay. I note that it is a little after five o'clock, and we have gone through three witnesses. I do believe the next witness is stipulated; is that correct?

MS. FLEMING: That's correct.

CHAIRMAN EDGAR: Okay. So what do we need to do in order to move through that witness?

MS. BRUBAKER: I would recommend that we, acknowledging the stipulated nature, go ahead and move the testimony into the record as though read, and also the exhibits.

CHAIRMAN EDGAR: Okay. The exhibits from witness Nunes will be entered into the record, or proffered by witness Nunes will be entered into the record, and his prefiled testimony will be entered into the record as though read, which means that we have moved through four witnesses today. So we're getting there.

(Exhibits Number 14 and 15 were admitted into evidence.)

MS. RAEPPLE: I believe we may be able to stipulate some additional witnesses at this time.

CHAIRMAN EDGAR: All right. Well, let's go ahead and see if we can do that. Thank you for the

suggestion, Ms. Raepple.

MS. RAEPPLE: We are prepared to stipulate Steve Urse if it's okay with the other parties.

MS. BRUBAKER: Staff has no objection.

MS. BROWNLESS: Your Honor, Mr. Urse would like to present his testimony.

CHAIRMAN EDGAR: Okay. Then we will -- at this point, then we will not stipulate witness Urse, and we'll see where we are tomorrow. Okay.

MS. BROWNLESS: My understanding is Mr. Fetter is only available today and that we can quickly do Mr. Fetter.

MS. RAEPPLE: That is correct. He is only available today. Are there any other witnesses that can be stipulated? We could stipulate Dale Bryk and Hale Powell.

MS. FLEMING: Staff doesn't have any objections to either one.

MS. BROWNLESS: And with regard to Ms. Bryk, the stipulation, as we understand it, would include the one exhibit that was not stricken, which is her third exhibit.

MS. RAEPPLE: That is correct.

CHAIRMAN EDGAR: Okay. So we can go ahead and stipulate the witness, Ms. Bryk, and her prefiled

testimony will be entered into the record as though read, and the exhibit that was proffered with her testimony will be entered into the record.

MS. BRUBAKER: That's Exhibit 60.

CHAIRMAN EDGAR: Thank you.

(Exhibit Number 60 was admitted into evidence.)

MR. PERKO: Madam Chairman, just to confirm, I'm not sure that we ever confirmed that Ms. Deevey was stipulated and excused.

MS. FLEMING: Yes, we did.

MS. BROWNLESS: And do we need to move her exhibits into the record as well, Your Honor?

MS. BRUBAKER: We originally planned to take it up as it came up in turn in testimony. If you would like to do it now, we certainly can do so.

CHAIRMAN EDGAR: Yes. Initially, that was my intention, to take up the witnesses as we go, but truthfully, if there are some things that we can take care of that we all agree on, let's go ahead and do that so that we know where we are starting tomorrow.

Okay. So witness Deevey, my understanding is that her -- I'm guessing her testimony can be entered into the record as though read. And were there exhibits?

MR. PABEN: Yes.

CHAIRMAN EDGAR: Okay. Let me get there.

MS. FLEMING: Ms. Deevey's exhibits were 75 through 81.

CHAIRMAN EDGAR: Okay. Thank you. So Exhibits 75 through 81 will be entered into the record.

(Exhibits Number 75 through 81 were admitted into evidence.)

MS. FLEMING: And Madam Chairman, if I may, since we're moving in stipulated exhibits, I do note that Breton and Heller and Norfolk and Pletka have been stipulated, so I would suggest at this time we move in their exhibits. Breton's exhibits are 32, 33, 34, 35.

CHAIRMAN EDGAR: Okay. Exhibits 32 through 35 will be entered into the record.

(Exhibits Number 32 through 35 were admitted into evidence.)

MS. FLEMING: Heller's exhibits are 43 through 45.

CHAIRMAN EDGAR: Exhibits 43 through 45 will be entered into the record.

(Exhibits Number 43 through 45 were admitted into evidence.)

MS. FLEMING: Witness Norfolk's exhibits are 46 through 48.

CHAIRMAN EDGAR: Exhibits 46, 47, and 48 will be entered into the record.

(Exhibit Number 46 through 48 were admitted into evidence.)

MS. FLEMING: And witness Pletka, 49 through 51.

CHAIRMAN EDGAR: Exhibits 49, 50, and 51 will be entered into the record.

(Exhibits Number 49 through 51 were admitted into evidence.)

MS. BRUBAKER: And for clarity of the record, that their testimony would also be entered into the record as through read?

CHAIRMAN EDGAR: And the prefiled testimony of those witnesses will also be entered into the record as though read.

Okay. Are there --

MS. RAEPPLE: There's also rebuttal for Mr. Pletka.

CHAIRMAN EDGAR: Rebuttal for witness Pletka, yes. Can we go ahead and do that as well? Yes. Okay. The rebuttal prefiled testimony of witness Pletka will be entered into the record as though read. Are there exhibits for the rebuttal testimony?

MS. BRUBAKER: No. They're all -- I think

we've --

CHAIRMAN EDGAR: We have covered them.

MS. BRUBAKER: -- covered everything. There's also --

CHAIRMAN EDGAR: And witness -- I'm sorry.

MS. BRUBAKER: I'm sorry.

CHAIRMAN EDGAR: That's okay. That's all right.

MS. BRUBAKER: I think we're about to repeat each other.

CHAIRMAN EDGAR: I hope so. Witness Para?

MS. BRUBAKER: We weren't.

CHAIRMAN EDGAR: We weren't.

MS. BRUBAKER: Just rebuttal, no exhibits.

CHAIRMAN EDGAR: I'm sorry?

MS. BRUBAKER: He had rebuttal testimony, only. There were no exhibits, so if we can just move the rebuttal testimony into the record.

CHAIRMAN EDGAR: So the prefiled rebuttal testimony of witness Para will be entered into the record as though read.

Now, does -- yes, Ms. Raepple.

MS. RAEPPLE: I was just going to say, the only -- the witness that we haven't yet addressed is the potential of stipulating Hale Powell, which we are

offering.

MS. BRUBAKER: And staff has no objection.

MR. JACOBS: We would like -- excuse me, Madam Chairman. We would like to have Mr. Powell testify.

CHAIRMAN EDGAR: Okay. All right. Then again, we will leave that for tomorrow.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JONATHAN P. NUNES

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

DOCKET NO. _____

SEPTEMBER 19, 2006

Q. Please state your name and business address.

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

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

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

Q. Please describe your responsibilities in that position.

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

Q. Please describe R. W. Beck.

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

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

Q. Please state your educational background and professional experience.

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

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

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

Q. Are you sponsoring any exhibits to your testimony?

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

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

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

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

A. The FMPA 2005 Load Forecast relies on an econometric approach to project electric sales by major rate classification in the service territories of the ARP Members. Econometric forecasting makes use of regression to establish historical relationships between energy consumption and various explanatory variables based on fundamental economic theory and experience. These historical models are evaluated and selected on their statistical ability to explain

variations in energy usage. The resulting models are then simulated using projections of the explanatory variables to produce forecasts of energy sales. Forecasts of net energy for load and peak demand are then derived from the energy sales forecast based on assumed loss and load factors, generally based on recent historical averages of these factors. Finally, the total ARP energy requirements and peak demand are based on summations of these load determinants across the Members supplied by the ARP and, in the case of coincident peak demand, assumed coincidence factors generally based on recent historical averages. Sections B.3.4 through B.3.7 of Exhibit__ [TEC-1] summarize the general methodology used to forecast load for each rate classification.

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

A. Yes. The City of Vero Beach has provided FMPA with its *Notice of Establishment of Contract Rate of Delivery* (CROD). The load forecast was developed assuming that Vero Beach's CROD becomes effective January 1, 2010. The effect of the notice on the forecast is that Vero Beach's load will no longer be included in the ARP load forecast once Vero Beach's CROD becomes effective. Also, the City of Fort Meade is included in the forecast beginning January 2009, at which time its load will begin being supplied by the ARP.

Q. Please summarize the All-Requirements Project's forecasted energy and demand?

A. The Base Case 2007 forecast winter peak demand is 1,458 MW, forecast summer peak demand is 1,499 MW, and forecast annual net energy for load is 7,480 GWh. The winter peak demand is projected to grow at an average annual growth rate of 2.6 percent from 2007 through 2009 (from 1,458 to 1,535 MW), and then grow at an annual rate of 2.1 percent from 2010 through 2024 (from 1,366 to 1,821 MW). The summer peak demand is projected to grow at an average annual growth rate of 2.5 percent from 2007 through 2009 (from 1,499 to 1,576 MW), and then grow at an annual rate of 2.1 percent from 2010 through 2024 (from 1,435 to 1,909 MW). Net energy for load is expected to grow at an annual average growth rate of 2.5 percent from 2007 through 2009 (from 7,480 to 7,858 GWh), and then grow at an annual average rate of 2.0 percent from 2010 through 2024 (from 7,157 to 9,456 GWh). Note that these growth rates reflect the addition of one ARP Member in January 2009.

Q. Were any alternative load forecasts developed?

A. Yes. In addition to the Base Case forecast that I just described, high and low case projections were developed to reflect various assumptions regarding future levels of population and economic activity. These high and low case forecasts are intended to capture 90 percent of the uncertainty in these long-term driving variables (1.7 standard deviations). Summaries of the results of the high case and low case forecasts are presented in Tables B.3-4 and B.3-5, respectively, of Exhibit__ [TEC-1].

Q. In your opinion are the assumptions used in the load forecasts reasonable for planning purposes?

A. Yes. The methodology used to estimate and simulate the forecasting equations is commonly accepted and widely used in the utility industry. The estimated parameters of the forecasting equations benchmark well against economic theory and the results of similar analyses done elsewhere. Historical data for ARP Members was provided by FMPA and are assumed to be accurate. Economic data was provided by Economy.com, a nationally-recognized provider of such data. Historical and normal weather data, on which the load forecast is based, were provided by the National Oceanic and Atmospheric Administration, a widely used source for weather data.

Q. Does this conclude your testimony?

A. Yes.

Q: Please state your name, occupation, and business address.

A: My name is Dale Bryk, I am a Senior Attorney for the Natural Resources Defense Council's Air and Energy Program, and my business address is 40 West 20th Street, 11th fl., New York, NY 10011.

Q: Please summarize your education and experience.

A: Currently I direct NRDC's state climate policy work. My expertise is in the area of state energy and climate policy, including utility regulation, energy efficiency and renewable energy programs, greenhouse gas emission registries and regulation, emissions trading, green building and smart growth. I joined NRDC in 1997, prior to which I practiced corporate law at Davis Polk & Wardwell in New York. Since 2002, I have also taught the Environmental Protection Clinic at Yale Law School. I have a J.D. from Harvard Law School, a Masters Degree in international law and policy from the Fletcher School of Law and Diplomacy and a B.A from Colgate University.

Q: What is the purpose of your testimony today?

A: This testimony is submitted in support of NRDC's intervention to advocate for the best and least cost option for meeting Florida's power needs, and in particular to explain why the integrated resource planning process, and the meaningful consideration of demand-side management and other alternatives to coal-fired power generation are so vitally important in connection with the proposed 765 MW coal-fired Taylor Energy Center (TEC) that has been proposed by Jacksonville Electric Authority ("JEA"), Florida Municipal Power Agency ("FMPA"), City of Tallahassee (Tallahassee), and Reedy Creek Improvement District ("RCID"). It is absolutely necessary to meaningfully consider efficiency, conservation, and other alternatives to new coal-fired generating capacity, and it is vital also to fully consider in this context the likely risks associated with impending future regulation of carbon dioxide (CO_2). Only by thoroughly and meaningfully evaluating the full suite of available options can the PSC ensure that a particular project

is the most cost-effective and least risky alternative available, and the best choice for Florida's energy consumers. Because of the short time frame for reviewing the record and developing testimony, my testimony provides only a summary overview of the relevant issues. Were more time available for examination and development of testimony I could address the relevant issues and facts of particular importance here in more detail.

Q: Why is integrated resource planning so important?

A: Most utility customers continue to receive service from hometown utilities, regardless of the status of retail competition in their state's electric industry, and these utilities have a solemn responsibility to engage in sensible electric-resource portfolio management. Such integrated resource planning (IRP) requires a fully integrated approach to identifying customer electric service needs and to selecting demand- and supply-side alternatives to meet those needs through a portfolio that minimizes total cost and environmental impacts, and has an acceptable level of risk.

Utility regulators bear a similar responsibility to enable effective portfolio management by aligning financial incentives with customer interests. In many cases, utility regulations are implemented so as to create a substantial financial *disincentive* for utilities to pursue cost-effective energy efficiency or other demand-side strategies. However, such disincentives can and should be eliminated.

Due to existing regulations governing utility cost recovery and default service procurement, most utilities invest exclusively in supply resources, and base their investment decisions exclusively on short-term contract price. They do not engage in long-term integrated resource planning and as a result, do not effectively manage risk for their customers. Regulators should require utilities to conduct such planning, which should include a comprehensive analysis of the costs, risks, and environmental impacts associated with all resource options – including both demand-side and supply-side resources. Achieving this goal in practice is difficult and requires particular expertise and

the ability to balance sometimes competing objectives. When the IRP process fails, the results can be dramatic; consider for example the California energy crisis of 2001.[1] This experience demonstrates forcefully that utilities and other service providers must assemble a robust and diverse portfolio that includes demand- and supply-side resources. By including serious demand-side measure, as well as a variety of supply-side options that include significant renewable resources, utilities and utility regulators can protect against risks, including those related to fuel prices, future loads, fuel supply availability, and future environmental regulations.

Q: Why is the IRP process so complex?

A: The complexity of the IRP process grows in part from the multitude of different customers that a utility must serve, and the widely diverging uses to which these customers put the electricity that a utility supplies. While utilities customarily think of electricity merely as a commodity (to be provided at a specific rate per unit), in some ways – especially when considering demand-side options – it is necessary to consider how that electricity is being used in order to identify the best alternatives for resource management. Moreover, a long-term view is necessary because of the need for capital-intensive investments with sometimes long lead times, and because many new resources will continue operating for thirty to forty years or more – so utilities and regulators must consider the costs, benefits, and risks of investing in a particular resource over an extended time horizon.

Without comprehensive and inclusive long-term integrated planning, a utility or utility regulator is likely to "miss the forest for the trees." And such short-sighted decisionmaking can be especially disastrous where some factors relevant to good

[1] In 2002, the California Legislature enacted Assembly Bill 57, returning the utilities to the role of portfolio managers. See California Public Utilities Commission (CPUC) Decision 03-12-062, December 18, 2003. The California Public Utilities Commission has adopted several subsequent decisions providing guidelines for the utilities' portfolio management activities. See, e.g., CPUC Decision 04-12-048, December 16, 2004.

resource planning (including DSM options like efficiency and energy conservation, and potential pitfalls like the regulation of CO_2 as discussed in testimony by Daniel Lashof) are under valued, under utilized, or left out entirely of the equation. While each individual decision may seem best in isolation, it is essential to consider the *additive* effect of the decisions and the impact each will have on the overall portfolio, since cumulative impacts may create significant future problems, for utilities and consumers alike. In the end, the preferred resource plan is generally the one that has the lowest lifecycle cost (i.e., lowest anticipated long-term revenue requirement) and is most robust in the face of various risks, among other factors.

Q: Why is the IRP process important in this case?

A: While comprehensive analysis of costs, risks, and environmental impacts is an important part of overall IRP planning, it is also an important element of the decisionmaking process for individual power plant projects. Specifically, for each proposed project the PSC must meaningfully assess both demand-side and supply-side resources that could meet customers' needs, and should account for both known risks and for reasonably anticipated but unquantifiable risks.

In this case, the first step in evaluating the appropriateness of the TEC project must be to scrutinize the determination that demand will exist for new capacity in the relevant service areas, and analyze the costs, risks, and environmental impacts associated with the *full range* of potential resource options – including a thorough and detailed analysis of demand-side opportunities that could avoid the need for new generation capacity in the time frame contemplated for the project and at much lower cost. This analysis should also include consideration of distributed generation, renewable resources, thermal resources (such as natural gas-fired plants and integrated gasification combined cycle coal plants), transmission, and more.

In point of fact, energy efficiency is the most *cost-effective, reliable, and environmentally friendly* resource available. However, the record for this project includes, for the most part, only a superficial evaluation of such alternatives. Appropriately assessing the potential for energy efficiency resources requires a detailed analysis of the full range of end-uses (i.e. how various customers use energy), how much more efficient those end-uses could be, and what level of efficiency is achievable through voluntary programs that provide incentives and information to customers to improve their efficiency or through mandatory standards that set a minimum level of required efficiency.[2] Determining what portion of that energy efficiency potential is cost-effective then requires a detailed and realistic analysis of the total cost to society of procuring the energy savings.

As an example of how meaningful demand-side analysis can, in fact, provide for real opportunities, the city of Tallahassee has commissioned a study that demonstrates that it can meet a large portion of its medium-term additional capacity expectations through demand-side strategies. An additional portion of Tallahassee's energy needs can be addressed by developing biomass alternatives. In addition to raising serious questions about whether there is a demonstrated need for the additional capacity from this project in Tallahassee (given its expectation of 192 MW of power from DSM and biomass), this example shows that a meaningful evaluation of alternative strategies can be fruitful, and should be required of all participants in the TEC project. It is apparent from the record here that such alternatives have *not* been fully explored.

Similarly, assessing supply-side options requires a realistic and inclusive analysis of the costs, attributes, and risks associated with each resource. Every resource's fixed

---

[2] California's recent analysis of the potential for cost-effective energy efficiency provides a good example of this type of potential study. See Rufo, M.; Coito, F. *California's Secret Energy Surplus: The Potential for Energy Efficiency*. Xenergy Inc. for the Energy Foundation and the Hewlett Foundation, 2002. www.energyfoundation.org/energyseries.cfm.

and variable costs should be assessed either over the lifetime of the resource or over some fixed period, often thirty years. In order to allow all resources to compete on a level playing field, this analysis must incorporate accurate operating, cost, and risk assumptions for each resource. For fossil-fueled resources, including coal-fired power plants, forecasting fuel prices (with a sensitivity analysis) is a critical element of this cost assessment. Additionally, in the context of coal-based generation, the real likelihood of carbon regulation is an essential component of the overall analysis. As discussed in the testimony of Dan Lashof, CO_2 regulation appears to be a virtual certainty. Given the cost implications of CO_2 emission regulations, as discussed in Mr. Lashof's testimony, the advantages of DSM and other capacity alternatives to coal-based generation look even more promising – both in term of good resource planning in general and with respect to the interests of the particular customers on whose behalf the PSC must act in this case. If the full range of potential risk is not adequately understood, the PSC cannot make an informed judgment on behalf of the state's ratepayers.

Risks come in different types and may occur on different time scales, but it is essential that the utilities assess and mitigate *all* risks that could have a significant impact on customers. There are generally at least three different types of risks:

1. Risks that can be quantified and for which historical experience exists that can be relied upon in assessing the future risk (for example, load forecasts, fuel price fluctuations; etc.);

2. Risks that can be quantified but for which little or no historical experience can inform the assessment of the risk (for example, regulation of carbon emissions); and

3. Risks that cannot be easily quantified, but can be qualitatively assessed (for example, a change in FERC's market design, public acceptance of new resource siting, etc.).

The utilities have traditionally emphasized the first type of risk listed above in their analyses. However, the other two types of risks are no less significant or real. Even if they can't be quantified *based solely on historical experience*, they can often be quantified and incorporated in a meaningful way into the integrated resource analysis. The financial risk associated with future regulation of carbon emissions is a prime example of the type of risk listed in the second category above that the utilities have historically failed to assess or mitigate, and that has not been addressed here for the TEC. Indeed, the risk analyses in this case are incomplete for two reasons: (i) they fail to fully analyze all relevant risks, and (ii) while they assessed the *magnitude* of the risk due to some factors, they do not explore a full range of possible options to *mitigate* these risks.

Finally, as one component of the analysis underlying this decision, the applicants must realistically evaluate (in light of CO_2-related cost implications and other factors) the relative benefits of natural gas-fired power generation, and the benefits of advanced coal technologies like IGCC. With regard to natural gas, the fact that prices have been falling (NYMEX natural gas futures are down from about $14 dollars a year ago to about $7.50 now (see http://wtrg.com/daily/gasprice.html)) means that outdated assessments that do not adequately account for such cost adjustments need to be updated. Similarly, assessments of natural gas-related costs that do not account for the inherently lower CO_2 emissions of natural gas, should be updated to account for the likely costs associated with future CO_2 regulation. Additionally, the possibility of employing alternative advanced coal-combustion technologies (such as IGCC) that have tangible CO_2 benefits must be thoroughly evaluated in light of expected CO_2 regulation in order for the PSC to meet its obligations to energy consumers.

Q: Why are environmental impacts important?

A: Different resource decisions will have widely varying environmental impacts. Coal-based power generation, for example, by far has the most profound adverse health and

environmental impacts. Coal plants emit air toxics, criteria air pollutants that cause smog, soot, and a wide range of adverse health conditions, as well as greenhouse gases that contribute to the threat of global warming and all of its associated ills. These impacts should be fully understood for each potential alternative resource, and should play a role in the PSC's balancing of different energy options. By analyzing the environmental profile of each type of resource, the utility and the PSC can assess the projected environmental impact of various options to help select an alternative that meets the objective of providing energy services in an environmentally responsible manner. This information is also necessary to assess the important element of financial risk exposure due to pollution emissions – one of the risk factors that directly relates to the cost-effectiveness and appropriateness of a particular energy resource option. For the TEC, the record does not appear to include a comprehensive assessment of comparative environmental impacts, and clearly does not incorporate a meaningful assessment the cost implications of potential environmental liability (including but not limited to the costs associated with future regulation of CO_2 emissions).

/s/ Dale Bryk
Dale Bryk
Senior Attorney
Natural Resources Defense Council

Q. Please state your name and business address.

A. My name is Dian Deevey and my address is 1702 SW 35th Place, Gainesville FL, 32608.

Q. Please briefly describe your educational background and work experience.

A. I received a bachelors' degree magna cum laude from Stanford University, in Philosophy. My early professional career was devoted chiefly to the design of computer systems (hardware and software), and artificial intelligence. In 1964 as an employee of United Technologies I received NASA funding to survey and review experimental approaches to the detection of life on Mars. From then until 1985 I conducted basic research in the biogeochemistry of the atmosphere, supported by NASA, as an employee of United Technologies and subsequently as an independent consultant. It featured the design and interpretation of field experiments on the biogenic sulfur cycle and on the chemistry of sea salt particles.. My research has focused chiefly on the natural sulfur cycle and sea salt particles. I received funding from NASA, NSF, and EPA, and designed, conducted, and interpreted field experiments. I retired from active research in 1985.

Q. Do you have experience in electric utility resource planning?

A. Yes. I have conducted detailed studies of the needs of my local municipal utility Gainesville Regional Utilities (GRU) for new capacity and ways to satisfy those needs for over three years.

Q. Why did you initiate these investigations?

A. Biogeochemistry of the atmosphere is a highly interdisciplinary field that integrates many subjects that are critically relevant to contemporary climate science, and fundamental to studies of the causes and consequences of global warming. I have followed scientific developments in global warming for many years. In 2003 when they planned a new coal-based generator, GRU management were oblivious to global warming issues, and believed

that emissions of carbon dioxide were unrelated to global warming. I am and was a member of the Alachua County Environmental Protection Advisory Committee (EPAC), and at my urging and other EPAC members, the County Commission formally requested EPAC to conduct a review of GRU's plans and their environmental impact.

Q. How was the review conducted and what was its outcome?

A. I conducted the review, with the help of Dr. David Harlos, a Gainesville resident with extensive experience in the health effects of air pollution. Together we produced a long written assessment of GRU's plans. This review was based on a careful study of GRU's plans and the reports of its consultants, together with extensive study of the voluminous literature of energy economics, integrated resource planning, demand side management, regulatory policy, legislative initiatives for the reduction greenhouse gas emissions both here and in other countries, and other important subjects. After about 18 months of intensive work, Dr., Harlos and I produced a written report of our findings[1], and at my request, the Alachua County Commission allocated money to pay for a professional peer review of the document.

Q. What did the reviewers report about your study?

A. The reviewers praised its professionalism, its balance, and its objectivity. All agreed with the findings, with a single minor exception. I was very gratified by the review.

Q. What in your opinion were the most important conclusions of your study?

A. We concluded that large investments in coal-based generators are too risky for municipal utilities in the present energy environment, given the extreme regulatory and technological uncertainties. Regulatory uncertainties derive from global warming and the need to reduce

[1] "Review of the Gainesville Regional Utilities' Proposal for a New Coal-Fired Power Plant" Prepared by Dian Deevey and David Harlos Sc.D. For The Alachua County Environmental Protection Advisory Committee Submitted to the Alachua County Board of County Commissioners. September 15, 2005, attached as Exhibit DD1.

carbon dioxide emissions very substantially in a short time, which will result in regulations that either impose financial sanctions on greenhouse gas emissions by utilities and/or offer subsidies that make other energy sources far more attractive to consumers. In both cases, the result could be financial problems for the utilities, their customers, and their municipal owners. There is a huge market for technological innovations in energy technologies that entail greatly reduced greenhouse gas emissions. Many established and new companies are working on radically new and possibly even revolutionary technologies to serve these growing markets. One promising possibility was announced in June by a Silicon Valley company called Nanosolar, which is one of several organizations working on novel solar PV technologies. They use a new nano-technology based solar PV system that is much easier and cheaper to produce than the conventional silicon-based system. Production is so cheap that it is expected to cut the cost of solar PV by a factor of four or five, making it cost-competitive with conventional electric energy over much of the world, and make distributed solar energy a reality in Florida and elsewhere.

Given these uncertainties, the prudent course for Gainesville and other municipalities is to make heavy demand side investments, and where possible adopt alternative energy sources.

Q. What is the purpose of your testimony today?

A. I have reviewed the application for a certificate of need by Jacksonville Electric Authority, ("JEA"), the City of Tallahassee, Reedy Creek Improvement District ("RCID"), and the Florida Municipal Power Agency ("FMPA") (hereinafter "Applicants"), for a 765 MW pulverized coal plant to be known as the Taylor Energy Center ("TEC"). I have two major criticisms of the Applicant's claim that a supercritical pulverized coal plant is the most cost-effective way to satisfy projected increases in the demand for electricity by the customers of the Applicants:

1. Applicants have not adequately assessed less costly means of meeting their projected demand. Testimony of other intervenors will demonstrate that Applicants have not adequately assessed the prospects of energy efficiency, conservation and demand-side management initiatives. It is my opinion specifically, that Applicants have not adequately evaluated generation of electricity using woody biomass, an alternative fuel with many environmental and cost advantages, or compared them to the other fossil fuel-based generators they have considered. Based on what I can ascertain from the Applicants' filings, their consultants appear wrongly to have assumed that woody biomass supplies are too limited in the locations of interest to support more than about 50 MW of capacity in any suitable location.

2. The participants base their estimates of the compliance costs of future greenhouse gas emission reduction regulations on (a) the 2005 version of the McCain-Lieberman Climate Stewardship Act, legislation which would be incapable of effective reductions in greenhouse gas emissions were it to be passed by the Congress, and (b) they also make a number of very questionable assumptions about how this act would be administered, the construction of nuclear power plants, reductions in the demand for electricity in other states than Florida, and the effectiveness of other sectors of the economy in reducing greenhouse emissions. The result is a set of estimates of allowance costs that is extremely low.

Q. What are your conclusions on the assessment by Applicants of alternative supply options to offset the pulverized plant, and specifically on the availability of biomass.

A. My knowledge of the participant's consideration of biomass-based generation is derived from reading Section A.6 of Volume A of their submission, and the testimony of Mr. Palatka, who supervised the preparation of Sections A.6.1 through A.6.4, where biomass and other alternative energy sources are discussed. Black & Veatch provided this material.

Black & Veatch did not explicitly rule out direct-fired wood-based generation, but they repeat the idea that fuel availability problems would limit size to a practical maximum of 50 MW, which is the case in many parts of the country, but not in the Southeast and, more importantly, not in Florida[2]. In any case, none of the TEC comparative studies seem to have included any conventional direct-fired biomass based generators.

Approximately half the land area of Florida is occupied by forests, and forest products are a very significant economic resource in the state. The income from forestry-based industries is Waste wood suitable for firing generators is very abundant in North and Central Florida. All the conventional forestry based industries in these areas produce waste wood, most of which is highly suitable for firing conventional spreader stoker generators, or feedstock for gasification. Florida's natural advantages for the production of biomass are illustrated by the difference between the goals of an NREL sponsored project to increase the tonnage of useable biomass from cropped land. The NREL target is 6 and 8 tons of biomass per acre per, while forests in Florida counties produce between 16 and 19 tons per year.

I have been working with a team of scientists in the School of Forestry and Conservation at the University of Florida who have conducted a detailed study of the potential for woody biomass based electricity generation in selected counties in the South East[3]. They found that most counties north of Orlando have very significant sources of woody biomass in the form of urban wood waste, forestry and mill residues and stumps. In addition, in most of them pine plantations provide pulp wood that could be purchased. Using these data, I have calculated that the Tallahassee municipal utility could fire a 100 MW generator at a fuel cost of 2 cents per kWh, assuming they purchased 60% of the urban waste wood and 70% of the forestry

---

[3] Hodges, Alan, and M. Rahmani, 2006 UF/IFAS Extension Fact Sheet, attached as Exhibit DD2.
Economic Impacts of Biomass-Fueled Electric Power Generating Plants in Selected Counties of the Southern United States. University of Florida/IFAS, Gainesville, Florida, Attached as Exhibit DD3. woody Biomass Fuel available to Tallahassee, ~~DD4~~ Attached as DD4.

residues and stumps available within travel time of about 1 hour. Haul distances and costs are based on detailed analysis of existing road networks, and are quite realistic.

Costs are slightly higher in Alachua County, but lower in Santa Rosa and Nassau Counties. We can expect comparable costs for a new power plant of 100 to 150 MW in Duval County (JEA).

Wood based generation is carbon neutral, and some cost advantages relative to fossil fuels can be expected to continue into the indefinite future, though owners of forests can be expect to raise their prices in parallel with the costs of emission allowances, once emission reduction legislation is passed and implemented. Utilities willing to go into debt to provide power to their municipal owners might well consider purchasing forest land to secure cheap sources of biomass from which to generate electricity in the future.

Q. Is there any other subject on which you wish to offer testimony?

A. Yes. I am concerned about the participant's use of extremely low carbon dioxide emission allowance prices, and the very questionable assumptions their consultants, Hill and Associates, used to arrive at these prices.

Applicants' forecasts of compliance costs per ton of CO2 emitted range from $4.22 in 2012, to a maximum of $10.28 in 2016, after which they drop rapidly to $2.43 in 2018, and rise very slowly through the interval 2017 to 2030 to a maximum of $9.52. While these are not the lowest cost estimates I have found in the literature, their erratic progression over time from low to high and then down again is unusual. The strange behavior of these prices appears to be the consequence of some very questionable assumptions made by Hill and Associates, who produced the estimates for the Participants. Here are some problems I have noted:

Hill and Associates based their estimates on the McCain-Lieberman Climate Stewardship Act of 2005, which provides for reducing the emissions of the all covered

entities in the United States to the levels emitted by the US in 2000. (These entities account for an estimated 85% US annual greenhouse gas emissions.) Compared to other legislative initiatives, this bill is extremely industry-friendly and in its present from will achieve very few reductions in total US emissions.

The bill as written provides that reductions begin in 2010, and Hill and Associates begin their analysis by determining the probable emission levels as of 2010 from Electricity Generating Units ("EGUs") as equal to 110% of EPA's estimate of emissions from this in the year 2000.) They then make the following assumptions:

1. Demand increases for some EGU's will not exceed 1% per year. No list of these EGU's is supplied, nor is the basis for selecting them fully described in the materials I have examined. This is what the relevant section of Volume A says about the method of selecting EGU's assumed to exhibit reduced demand growth: "A reduction in electricity demand growth. In the regulated-CO2 fuel and corresponding emission allowance price sensitivity scenario, electricity demand growth was limited to 1.0 percent in any area of the country that had exceeded 1.0 percent in the base case fuel price forecast."

I could find no estimate of the proportion of energy production accounted for by these EGUs, or their greenhouse gas emissions. The basic idea that some utilities will experience reduced demand growth, while the Applicants and other Florida utilities experience very significant demand growth seems illogical and should be substantiated. At the very least, one needs detailed data to determine how this assumption affects the outcome of the allocation price analysis.

2. Electric utilities in states which do not currently have any renewable energy standards are projected to aggressively shift to carbon-free energy sources. The Applicants project that electric utilities in states which do not currently have any renewable energy standards will produce an average of 12% of their energy from carbon-

free ("non-emitting") sources within two years (2009), and increase their percentage of carbon-free energy production by 0.5% per year thereafter until they have achieved a total of 20% renewable energy sources. It is not clear how this is to be achieved, or whether the Applicants themselves plan to assume the burden of this conversion, as all are electric generating utilities in states that presently have no renewable energy portfolio standards.

3. Hill and Associates assume that 12 nuclear plants will come on line between 2016 and 2020, and that these will be considered non-emitters. Analysts increasingly challenge the notion that nuclear power is carbon-free, on the grounds that building and fueling them entails very significant carbon dioxide emissions equal to about one third of the greenhouse gas released by natural gas-fueled combined cycle generators with an equivalent capacity release. (Other life cycle considerations suggest that nuclear generation is not the solution to greenhouse gas reduction needs that many have assumed it to be.)

4. Aggressive reductions by non-electric generating industries. Hill and Associates also assume that other US industries covered by S 1105 will achieve more than their proportionate share of greenhouse gas reductions, which reduce the cost of tradable emission credits, and will relieve the need of EGU's to make genuine CO2 emission reductions, or even to purchase expensive allocations. The Applicants fail to provide any reasonable analysis which supports this conclusion. As recognized by the Union of Concerned Scientists in their report "Gambling on Coal: How Future Climate Laws Will Make New Coal Plants More Expensive," each new coal plant represents an enormous long-term increase in green house gases. UCS documents in its report that one 500 MW coal electric plant represents the green house gas equivalent of 600,000 cars each year. More than 150 new coal plants, most of which are of much greater capacity than 500

MW, are tentatively planned for development in the US. Unlike cars, coal plants will operate 40 to 50 years. There is virtual certainty that the any meaningful regulation of carbon and other green house gases will focus primarily on coal-fired electric plants because they are and will continue to be the largest source.

5. Further economic relief for EGU industry. The final very questionable assumption is that political pressure on the federal government will force it to give the EGU's relief in the form of special offset credits in order to buffer electricity customers from higher electricity costs. Given the recent accounts of hyper-earnings for energy companies, combined with the incredible economic burdens higher energy prices have placed on household incomes, it seems impractical that it will be politically acceptable to provide consumer relief from these higher prices by offering further supports to the energy companies.

Given the reliance on a notoriously industry-friendly legislation, the large number of additional questionable assumptions made by Hill and Associates, and the lack of data on the impact of each of these curious assumptions, I find it impossible to have any confidence in the forecast of costs of compliance with future greenhouse gas emission reduction legislation.

Q. Do you favor other estimates of compliance costs?

A. Yes. I am familiar with the several publications by consultants at the firm Synapse Energy Economics, and regard them as among the best available. Their report "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning is attached to this testimony (Ex. DD 5). This firm is responsible for an evaluation of compliance costs for one of the Applicants—the City of Tallahassee Electricity Department—and I think their estimates should have been used by all the participants. At the very least, the Participants should have performed and compared the impact of compliance prices provided by Synapse

with those provided by Hill and Associates. A conservative analysis of the most reasonable allowance costs demonstrate that they will increase the costs to operate coal electric plants, perhaps by as much as one-half. That's 40 to 50 years of grossly misstated operating costs if the most reasonable allowance estimates are not used.

There is one respect in which I would supplement the analysis from consultants at Synapse. I think that reviews of greenhouse gas-limiting legislative initiatives should consider the goals of the legislation—the specific tonnage of emission reductions—and determine through economic modeling whether those goals are met. Several studies of legislative proposals by the EIA have taken this approach, and found that without much higher economic sanctions than are found in many of the studies cited by Synapse, little or no actual reduction in emissions occurs. This is especially true of legislation that features low trigger prices for tradable emission rights that result in temporary lifting of the relevant caps until auction prices decline. These are typically favored by industry, but they do not achieve the stated goals of the legislation.

If legislation is to achieve the large greenhouse gas emission reductions that scientists tell us are urgently needed, the costs of allocations must be approximately the same as the costs of technology that achieves the reduction. At present, many analysts see carbon capture and sequestration as the best hope of avoiding disastrous climate effects while still provided reliable and economic electric energy to the world. Ex. DD6, attached.

The cost of removing carbon dioxide from the flue gas of a coal or natural gas fired generator should be considered in every integrated resource plan that considers these technologies. Useful estimates of the comparative costs of carbon capture and sequestration for pulverized coal generators, IGCCs and NGCCs combined cycle units has been published by Rubin, Bau and Chen, of the Carnegie Mellon University, who present representative costs in the range

of $26 to $47 dollars per ton of CO2 emissions avoided. These costs include capture and compression of the CO2, but not transport to a storage site.

In my opinion, use of the most industry friendly greenhouse gas legislation introduced into the Congress as a basis for estimating the future cost of compliance grossly misrepresents the potential costs both to utility customers and to the municipalities that own the utilities. It is now a well accepted principle among knowledgeable scientists that avoidance of the most serious effects of global warming requires drastic reductions in green house gases, perhaps as much as 80 percent. This makes the adoption of federal policies as proposed by Applicants, entailing significantly more modest reductions, seem unlikely. Both the US Senate and the US House of Representatives have adopted resolutions acknowledging the scientific threat of global warming, and expressing intent to address this threat in such a way as to protect the economy and public safety.[4] Reliance on cost projections which assume significantly less stringent reductions will be government policy is imprudent of these Applicants. A conscientious study should include the most recent legislative initiatives, specifically the Safe Climate Act introduced in the US Senate last June by Senator Jeffords (S. 3698) and the companion bill introduced by Representative Waxman in the US House (HR 5642).

Q. Why is it important to address these issues in the certificate of need proceedings?

A. If the pulverized coal plant is approved without requirements for management of emissions that reflect the imminent regulatory environment, the effect of the new regulations will be completely shifted to consumers as the Applicants pass their compliance costs through. Perhaps a greater concern relates to carbon emissions. If this plant is approved and future regulations greatly reduce allowable carbon emissions, there is no commercial or economical method for post-combustion removal of carbon dioxide from a supercritical,

[4] Sense of the Senate on Climate Change, H.R. 6 §1612, Energy Policy Act of 2005 (Approved 54-43),

pulverized coal plant as proposed by Applicants. Thus, new regulations on carbon emissions will have a particularly dramatic economic effect on consumers' pocketbooks.

There is tremendous potential for biomass to cost effectively meet the capacity needs of the Applicants. By acquiring additional biomass, following the City of Tallahassee's lead, the capacity needed by the Applicants will be reduced and the power available to the Applicants from biomass will be available in a shorter period of time. Based on my review of what the Applicants submitted in this proceeding, the Commission should know that nobody can reasonably evaluate whether the proposed TEC coal plant is needed or whether it is the most cost-effective source of energy without a serious analysis of the potential for biomass to cost-effectively meet the capacity needs of the Applicants. Tallahassee's independent evaluation of the biomass alternative, and the resulting contract between the City of Tallahassee and a biomass provider, should be sufficient cause for the Commission to reject the Applicants petition until a serious evaluation of the biomass alternative is performed by independent experts.

Q: Are you sponsoring exhibits?

A: Yes. The exhibits referenced in my testimony are attached to the testimony and incorporated herein.

Q. Does this conclude your testimony?

A. Yes. Given the insufficient time to prepare additional analysis and testimony, or to perform discovery to identify additional flaws in the Applicants' petition, this is all that I am able to present to the Commission at this time.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF DR. THEODORE R. BRETON

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. _____

SEPTEMBER 19, 2006

Q. Please state your name and business address.

A. My name is Dr. Theodore R. Breton. My business address is 4401 Fair Lakes Court, Suite 400, Fairfax, Virginia.

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

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

Q. Please describe Pace Global Energy Services.

A. Pace Global is an independent energy management and consulting company that provides strategic and technical expertise in fuels, electric power, finance, risk management, and energy management in both domestic and international energy

markets. We provide an independent source of energy expertise support to energy developers, financial institutions, public utilities, commercial and industrial consumers, and public sector agencies. Our headquarters are near Washington, DC, and we have regional offices in Houston, Columbia, London, Moscow, and New York City.

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

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

Q. Please describe your educational background and experience.

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

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

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

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

Q. Are you sponsoring any exhibits to your testimony?

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

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

A. Yes. I am sponsoring Sections A.4.6.3, A.4.6.4, A.4.6.5.3, and A.4.6.5.4, all of which were prepared under my direct supervision.

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

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

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

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

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

Our gas supply forecast is provided for US production, Canadian and Mexican net imports, and imported liquefied natural gas (LNG). These forecasts are developed based on our review of natural gas reserves in North America, production costs, and consumption forecasts for Canada and Mexico. The near- and medium-term supply of imported LNG is based on our assessment of the amount of LNG available from existing and new liquefaction terminals worldwide, taking into account contracts and forecast requirements for LNG

worldwide. Longer term supplies of LNG (after 2012) are forecast to be available to meet demand at a price consistent with world oil prices and the potential to convert "stranded" gas reserves to liquids.

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

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

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

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

A. We see the United States becoming increasingly dependent on LNG imports to meet natural gas consumption over time. Our 4Q 2005 forecasts project that this

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

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

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

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

A. Pace Global's 4Q 2005 forecast assumed that the U.S. economy would grow over time, causing an increase in the demand for natural gas. Over the 2004-2010 period, annual natural gas consumption was projected to increase by 0.9 percent in the residential/commercial sectors, to decline by 0.4 percent in the industrial sector, and to increase by 4.3 percent in the power sector. As a result of the current era of higher-cost natural gas, many industries that formerly used

low-cost natural gas to produce energy-intensive commodities, such as fertilizer, are no longer competitive, so production of these commodities is moving to other parts of the world.

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

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

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

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

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

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

A. The natural gas supplied to Florida is transported from the US Gulf Coast, so the price in Florida is closely tied to the Henry Hub price. With the exception of the

transportation cost elements specific to Florida, natural gas prices within Florida are affected by the same factors that affect natural gas prices throughout the nation.

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

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

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

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

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

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

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

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

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

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

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

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF JAMES HELLER

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. _____

SEPTEMBER 19, 2006

INTRODUCTION

Q. Please state your name and business address.

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

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

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

Q. Please describe Hellerworx.

A. Hellerworx is a consulting firm that assists power generators, transportation companies, and energy producers in solving economic and technical problems related to energy and transportation markets and environmental compliance issues. The types of work in which we have experience include negotiating

transportation and fuel supply agreements, risk and competitor analysis, strategy development, fuel and transportation planning and management, fuel price forecasting, siting new energy facilities, rail fleet planning and management, and litigation and regulatory support services.

Q. Please describe your educational background and experience.

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

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

co-founded Fieldston Transportation Services, which managed railcars for various customers.

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

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

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

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

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

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

Q. Are you sponsoring any exhibits to your testimony?

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

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

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

Q. How did you become involved in this proceeding?

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

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

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

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

Q. Have rail rates increased in recent years?

A. Yes.

Q. What caused this increase in rail rates?

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

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

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

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

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

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

A. Yes. The testimony of Paul Hoonaert on behalf of Sargent & Lundy indicates that the plant design will allow TEC to burn a wide variety of coals and petroleum coke from various regions.

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

A. Yes.

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

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

While the derailments and emergency track maintenance on the Joint Line during 2005 caused disruptions, not only have those largely dissipated, but the carriers are setting records for PRB shipments. Although BNSF and UP will likely continue to plan their capacity additions in the PRB to match rather than

exceed demand (and therefore congestion is likely to recur periodically when demand for PRB coal is higher than expected), past events also suggest that, over the long term, investment in the PRB rail system is likely to be adequate to meet demand growth. For example, between 1995 and 2004, Wyoming PRB coal production increased by approximately 135 million tons, from 246 to 381 million tons. Over this period, BNSF alone invested a total of about $2.1 billion to increase its coal-hauling capacity (primarily in the Wyoming PRB), including over $1.5 billion invested in locomotives and railcars, and approximately $550 million invested in track expansions. Although similar data for UP are not publicly available, UP's investments in coal-hauling capacity over the same period were likely of roughly similar magnitude.

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

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF PETER NORFOLK

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. _____

SEPTEMBER 19, 2006

Q. Please state your name and business address.

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

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

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

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

A. Simpson, Spence & Young Consultancy & Research Ltd (SSY) is the world's largest independent ship brokering group. SSY has established an organic and dynamic organization over the last 125 years that delivers traditional brokering expertise with technological sophistication and innovation. We have taken a

proactive approach to brokering and advise our clients of future market trends, developments, and opportunities, as well as anticipating their own growing and changing requirements. SSY provides global coverage to our clients through our offices in 11 countries. We provide a broad range of shipping services to our customers. The services we provide focus in the following areas:

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

Q. Please describe your educational background and experience.

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

Q. Are you sponsoring any exhibits to your testimony?

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

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

A. Yes. I am sponsoring Section A.4.6.7, which was prepared under my direct supervision.

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

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

Q. How did you become involved in this proceeding?

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

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

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

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

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

World trade in key industrial cargos (for example, iron ore and coal) is expected to increase, including the prospect of increased Asian steam coal imports,

because of the introduction of new coal fired power generating capacity, plus expansion in the steel industry of India and upside potential for China's grain imports. Combined, these factors will likely ensure that dry bulk trade over the balance of the decade remains above historical averages.

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

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

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

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

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

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

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

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

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

(on a tonnage basis) are between 20 to 24 years old, providing a large potential for accelerated demolition once the freight markets enter a period of severe downsizing.

Q. What effect does this have on your analysis?

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

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

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

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

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

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

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

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF RYAN J. PLETKA

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. _____

SEPTEMBER 19, 2006

Q. Please state your name and business address.

A. My name is Ryan J. Pletka. My business address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

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

A. I am employed by Black & Veatch Corporation. My current position is Project Manager.

Q. Please describe your responsibilities in that position.

A. As a Project Manager in Black & Veatch's renewable energy group, I am active in assessments of advanced, distributed, and renewable energy technologies. I have participated in Black & Veatch assessments of over 70 renewable energy projects and technologies. Project types have included strategic planning, policy

advisory, feasibility studies, due diligence investigations, new technology evaluations, engineering and financial analyses, critical flaw reviews, market analyses, and project proposal evaluation. This experience includes evaluation of around 200 project proposals from developers of all types of renewable energy projects.

Q. Please describe Black & Veatch.

A. Black & Veatch Corporation has provided comprehensive engineering, consulting, and management services to utility, industrial, and governmental clients since 1915. Black & Veatch specializes in engineering, consulting, and construction associated with utility services including electric, gas, water, wastewater, telecommunications, and waste disposal. Service engagements consist principally of investigations and reports, design and construction, feasibility analyses, rate and financial reports, appraisals, reports on operations, management studies, and general consulting services. Present engagements include work throughout the United States and numerous foreign countries.

Q. Please describe your educational background and professional experience.

A. I have a Bachelors and a Masters of Science degree in mechanical engineering from Iowa State University.

I have been involved in projects representing a wide variety of generation technologies including wind, biomass and waste, energy storage (batteries, compressed air energy storage, ultra-capacitors), cogeneration, microturbines,

fuel cells, Stirling engines, solar photovoltaic, solar thermal, geothermal, hydroelectric, ocean energy, zero-point (free energy), and gasification, in addition to various conventional technologies. I am Black & Veatch's lead analyst of government incentives and regulatory policies for renewable energy. I have evaluated projects involving the production tax credit, accelerated depreciation, investment tax credit, renewable energy production incentive, unconventional fuels credit, net metering, green pricing, renewable energy credits, Clean Renewable Energy Bonds, renewable portfolio standards, and various state-specific grants, rebates, and other programs. A special area of emphasis is biomass technologies. I am knowledgeable about technologies for biomass gasification, combustion, pyrolysis, cofiring, landfill gas (LFG), and production of biofuels (ethanol and biodiesel).

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

A. The purpose of my testimony is to provide an overview and summary of the renewable technologies evaluated as supply-side alternatives to meet each Participant's capacity needs. I will also describe the advanced technologies, energy storage technologies, and distributed technologies considered.

Q. Are you sponsoring any exhibits to your testimony?

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

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

A. Yes. I am sponsoring Section A.6.1, A.6.3, A.6.4, and A.6.5, all of which were either prepared by me or under my direct supervision.

Q. What renewable technologies were considered as alternatives to TEC?

A. There were several renewable technologies analyzed to determine whether renewable energy was a viable alternative to TEC. The renewable technologies considered include solid biomass (direct-fired, gasification, and integrated gasification combined cycle [IGCC], and co-fired), biogas (anaerobic digestion and LFG), waste-to-energy (WTE, including mass burn and refuse derived fuel [RDF]), wind (onshore and offshore), solar (solar thermal and solar photovoltaic [PV]), geothermal, hydroelectric, and ocean energy (ocean thermal energy conversion, wave, marine, current, and tidal) technologies.

Q. What are advanced technologies?

A. Advanced technologies include developmental technologies approaching commercial status that may offer the potential for cost and efficiency improvements over conventional technologies.

Q. What were the advanced technologies considered as alternatives to TEC?

A. The technologies evaluated include advanced combustion turbines, fuel cells, and advanced coal.

Q. What are energy storage technologies?

A. Energy storage technologies convert and store electricity, increasing the value of power by allowing better utilization of off-peak baseload generation and the mitigation of instantaneous power fluctuations. Different types of technologies are available that provide a variety of storage durations. Storage durations range from microseconds (superconducting magnets, flywheels, and batteries), to minutes (flywheels and batteries), to hours and seasonal storage (pumped hydroelectric, batteries, and compressed air).

Q. What energy storage technologies were considered as alternatives to TEC?

A. Energy storage technologies evaluated include pumped hydroelectric, battery storage, and compressed air energy storage (CAES).

Q. What are distributed generation technologies?

A. In general, distributed generation options are small, modular units that are placed near customer load points and, when operated, can reduce a utility's demand. Distributed generation alternatives can also be used to provide baseload for smaller utilities.

Q. What distributed technologies were considered as alternatives to TEC?

A. Two types of distributed generation technologies that were analyzed are reciprocating engines and microturbines. In addition, fuel cells were considered under advanced technologies, and solar photovoltaic was considered under renewable technologies.

Q. Please describe how the costs and performance parameters of the nonconventional (renewable, advanced, energy storage, and distributed generation) technologies were developed.

A. Estimates for costs and performance parameters were based on Black & Veatch project experience, vendor inquiries, and literature reviews. Capital costs are in 2006 dollars and reflect the total project cost, including direct and indirect costs. Levelized costs are based on the municipal tax exempt bond rates presented in Section A.4 of Exhibit __[TEC-1]. Owner's costs were not included in the total project cost because such costs vary significantly for nonconventional (renewable, advanced, energy storage, and distributed generation) technologies. The inclusion of these owner's costs would further increase the cost of the non-conventional (renewable, advanced, energy storage, and distributed generation) technologies and decrease their competitiveness. When appropriate, ranges of costs and performance estimates for each nonconventional (renewable, advanced, energy storage, and distributed generation) technology were developed to create best and worst case scenarios for capital cost, net plant output, net plant heat rate, fixed and variable operations and maintenance (O&M) costs, and operating capacity factor. These ranges of costs and performance create a band that helps to provide more reasonable analyses considering the many uncertainties associated with nonconventional (renewable, advanced, energy storage, and distributed generation) technologies.

Q. Have renewable energy incentives for private developers been considered?

A. Yes. Examples of renewable energy incentives include production tax credits, accelerated depreciation, and miscellaneous grant and loan programs. However, there is uncertainty related to the applicability and renewal of these incentives.

Q. What is the current applicability of the federal production tax credit incentive?

A. The production tax credit (PTC) is currently in effect for projects that enter commercial operation by December 31, 2007. Projects that may benefit from the PTC include wind, biomass, geothermal, solar, municipal solid waste, some types of hydro, and landfill gas. Unless the PTC is renewed, renewable energy projects that enter commercial operation after the current deadline of December 31, 2007, will not be eligible for the PTC. In addition, the project owner must be a taxable entity, unlike the Participants, to directly receive the benefits of the PTC.

Q. How do these incentives influence a project's cost of energy?

A. Qualification for incentives has the potential to decrease the costs of renewable energy supply-side alternatives for independent power producers, investor-owned utilities, and other tax-paying entities.

Q. Are these incentives available to the Participants directly?

A. No. Most renewable energy incentives are designed as tax credits and would not be applicable to the Participants in a conventional municipal ownership

structure. A taxable entity may be able to utilize these tax credits and thereby offer a lower net energy price to potential energy purchasers.

Q. What factors are important when evaluating nonconventional (renewable, advanced, energy storage, and distributed generation) alternatives other than economic or cost factors?

A. There are a number of noneconomic aspects of nonconventional (renewable, advanced, energy storage, and distributed generation) alternatives that should be considered. These include the technology's developmental status, fuel availability or resource availability to generate electric energy, reliability, feasibility, and the technology's overall ability to meet each Participant's forecast capacity needs.

Q. Have all nonconventional (renewable, advanced, energy storage, and distributed generation) technologies considered achieved commercial operation status?

A. No. Several of the nonconventional (renewable, advanced, energy storage, and distributed generation) technologies considered are still in the research and development stage. These technologies are either conceptual or are still operating only in pilot or demonstration facilities and are not developed enough to be considered commercially available. Technologies that are not considered commercial include biomass gasification with IGCC, parabolic dish, central receiver, solar chimney, ocean thermal, and marine current technologies.

Q. Do all the nonconventional technologies have adequate resources available within the State of Florida?

A. No. Several renewable technologies do not have adequate resources available for cost-effective electric power production in Florida. Because of transmission system limitations, nonconventional technology alternatives considered in this analysis were geographically limited to the state of Florida. As a result, if adequate resources are not available within Florida, several renewable alternatives are not viable for electric generation in Florida. The technologies with insufficient resource availability in Florida include wind energy, solar parabolic trough, geothermal, and hydroelectric technologies.

Q. Is LFG a viable renewable alternative within Florida?

A. Yes. However, while LFG is available at various sites throughout Florida, many of the most promising potential projects are already being utilized by other utilities, including JEA. Additionally, the amount of LFG available is not sufficient to mitigate the need for additional capacity for any of the Participants.

Q. Are solid waste technologies such as municipal solid waste (MSW) and RDF available within Florida?

A. Yes. Excluding cost and environmental factors, there is some availability of MSW and RDF resources within Florida.

Q. Is solar PV available within Florida?

A. Yes. Excluding cost factors, there is substantial availability of solar PV resources within Florida.

Q. What renewable technologies have adequate resource availability and are commercially proven?

A. The renewable technologies that potentially have adequate resource availability and are commercially proven include MSW, RDF, PV, co-fired biomass, direct-fired biomass, and anaerobic digestion.

Q. Are any advanced technologies viable from a development status or technology feasibility standpoint?

A. No. Given the needed capacity, the advanced combustion turbine, fuel cell, and coal technologies are still considered developmental stage technologies. Due to the early developmental stages of these technologies and the uncertainty relating to reliability and cost, these advanced technologies were not considered commercially viable at this time.

Q. Discuss the development status and technological feasibility of energy storage and distributed generation technologies?

A. Each of the energy storage technologies (pumped hydroelectric, lead-acid battery, and compressed air) stores energy collected during off-peak hours and then releases the energy during peak demand periods. Energy storage systems were considered commercially proven. However, because these technologies

rely on storing energy during off-peak periods, they are limited to only peaking applications and, therefore, have lower availability than other conventional alternatives. As a result, energy storage technologies cannot be considered for based load capacity.

Distributed generation technologies are typically used for small demand applications. Reciprocating engines are considered commercially proven, while microturbines are in early commercial deployment. Distributed generation systems are often very small in size.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REVISED REBUTTAL TESTIMONY OF RYAN J. PLETKA

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. 060635-EU

DECEMBER 26, 2006

Q. Please state your name and business address.

A. My name is Ryan J. Pletka. My business address is 11401 Lamar Avenue, Overland Park, Kansas 66211.

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

A. I am employed by Black & Veatch Corporation. My current position is Project Manager.

Q. Have you previously submitted testimony in this proceeding?

A. Yes.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. Exhibit No. __ (RJP-1R) is a chart showing historical biomass unit sizes.

Q. Have you reviewed the testimony of Dian Deevey that was filed in this docket on November 2, 2006?

A. Yes, I have.

Q. Have you reviewed the testimony of Dale Bryk that was filed in this docket on November 2, 2006?

A. Yes, I have.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut the claims by Ms. Bryk that biomass options were not fully explored in the TEC Need for Power Application, Exhibit No. __ ([TEC-]1). Finally, I will rebut Ms. Deevey's claims that new solar technologies are a reality and that biomass has not been adequately addressed.

Q. Please describe your experience with biomass.

A. I am one of Black & Veatch's lead engineers in assessment of biomass fuels and technologies. I have been involved in projects utilizing a variety of biomass fuels, including wood, energy crops, animal manure, municipal waste, agricultural residues, and industrial wastes. Areas of emphasis include combustion, gasification, pyrolysis, biogas, and production of alternative fuels (e.g., ethanol, biodiesel, and bio-oil). In Florida, I have worked on biomass related projects for the Florida Department of Environment Protection, Orlando Utilities Commission, Gainesville Regional Utilities, JEA, Lakeland Electric, and other clients. I have a mechanical engineering background with graduate-

level specialization in gasification, biomass energy, fluidized beds, and energy storage. My master's thesis was based on a novel pyrolytic gasification process for biomass fuels and included design, construction, and testing of a pilot scale biomass gasifier.

Q. On Page 7 of her testimony, Dale Bryk suggests that a biomass supply-side resource alternative was not "fully explored" by each Participant. Has each Participant appropriately considered biomass resources?

A. Yes. The biomass alternatives considered were solid biomass (direct-fired, gasification and integrated gasification combined cycle [IGCC], and co-fired), biogas (anaerobic digestion and LFG), waste-to-energy (WTE, including mass burn and refuse derived fuel [RDF]). These are all the technologies that are either commercially proven today or have some potential in the near to mid-term.

For each of these non-conventional technologies, cost and performance parameters were developed based on Black & Veatch project experience, vendor inquiries, and literature reviews. These parameters were used to calculate the levelized cost of energy for each technology. In addition to economics, there are other important factors when evaluating non-conventional alternatives. These include the technology's developmental status, fuel availability or resource availability to generate electric energy, reliability, feasibility, and the technology's ability to meet each Participant's forecast capacity needs. Due to a

combination of these factors and economics, most of the non-conventional alternatives are not viable alternatives to TEC.

Q. On Page 5 of her testimony, Dian Deevey suggests that woody biomass was not "adequately addressed" by each Participant. Do you agree?

A. No, for the same reasons I have discussed previously.

Q. Page 5 of Ms. Deevey's testimony also indicates her opinion that "consultants appear to have wrongly assumed that woody biomass supplies are too limited in the locations of interest to support more than about 50 MW of capacity in any suitable location". What was the basis for selecting the 30 MW size of the direct-fired biomass facility?

A. Selection of the appropriate size for a biomass plant must consider numerous factors including site constraints, emissions caps, risk, need for capacity, fuel supply and technology issues. Of these, the most important is fuel supply. Resource availability is critical to the success of biomass power plant applications. Due to the dispersed nature of the feedstock and high transportation costs, it is preferred to site the plant as close to the fuel source as possible.

Historically most direct-fired biomass plants have relied on local waste biomass from sources such as sawmills, pulp and paper production, and urban wood waste. These resources have typically been low cost and local. Their limited supply has often resulted in relatively small scale biomass facilities, usually less

than 50 MW. Since 1950, the average unit size of direct fired biomass plants has been between 10 and 35 MW. This is shown in Exhibit No. __ (RJP-1R). Although the average unit size is increasing somewhat, it is still much smaller than coal fired plants. A plant size of 30 MW is considered typical and representative of direct-fired combustion biomass alternatives.

Q. Are larger direct-fired combustion biomass facilities possible?

A. Yes, larger facilities are possible, but practically, biomass facility size is constrained by two factors: (1) technology experience with large scale and (2) the maturity of the fuel supply chain.

There is no experience with biomass plants of the scale of TEC. As discussed previously, biomass plants are typically less than 50 MW in size. To my knowledge, the largest stand-alone biomass plant in the United States is the 80 MW Multitrade plant near Hurt, Virginia. There is one 240 MW circulating fluidized bed (CFB) plant in Finland that is capable of burning woody biomass. However, this plant normally burns a mixture of lignite coal, peat, and wood.

In addition to limited experience with large unit sizes, biomass power plants are also constrained by fuel supply economics and logistics. Biomass plants nearly always rely on very low cost (or free) waste fuels, such as sawmill residues. Fuel cost must be low to keep power prices low. With low cost fuels, transportation cost can be the largest component of overall fuel costs. It is important to keep transportation distance short to keep overall fuel prices down

and ensure an economically viable project. This limits the resource collection area that can be cost-effectively accessed, which, in turn, limits the size of the project.

Another factor that uniquely affects biomass plants is that the more fuel a biomass plant needs, the more likely the fuel price is higher. This is because of the transportation cost issue discussed above, but also because very large biomass plants must secure huge quantities of fuel. Large plants affect the regional supply and demand balance by greatly increasing demand. These plants essentially become high "price makers" in a market rather than low "price takers."

Q. Is it currently viable to fully displace the need for TEC with biomass?

A. No. TEC is very large relative to current biomass experience. As discussed previously, it is not practical or economically viable with current biomass technologies to develop a biomass power plant to the same scale.

Q. On page 7 of her testimony, Ms. Deevey mentions the possibility of utilities purchasing forest land to secure biomass supply. Is purchasing large tracts of forestland a viable strategy for securing a biomass fuel supply?

A. Purchasing timberland for fuel harvesting would be very expensive compared to other biomass sources. Meeting the annual fuel requirement of a utility-scale biomass power plant would require the purchase of thousands of acres of timberland, the cost of which would be similar to, if not higher than, the total

capital cost of the biomass power plant. Due to the long growing rotation of commercial timber, even more land would need to be purchased to provide a long-term fuel supply to the plant. Costs for harvesting and processing the material and finally transporting it to the plant would add even further to the overall delivered fuel cost. Timber is much more valuable when harvested for other uses, such as dimensional lumber or pulp. Biomass fuels are most economically feasible as byproducts or residues of some other material processing operation (e.g., sawmill residues, pallet residues, urban wood waste, etc.).

Q. Page 4 of Ms. Deevey's testimony discussed Nanosolar. Are you familiar with the technology developed by Nanosolar?

A. Yes, we have reviewed their technology. They use printing technology to produce thin-film photovoltaics that use no silicon and are hoping for an 80 percent cost reduction in production.

Q. What is the status of the Nanosolar technology?

A. They are still an early stage company, with venture backing. They are planning a production facility in the San Francisco Bay area for 2007, but it is not certain when quantities of material will be available.

Q. Why was Nanosolar not considered in the review of technology alternatives?

A. This technology is not currently available today, nor is it likely to be available in large enough quantities in the timeframe required. Costs are speculative at this time. Conventional solar photovoltaic technologies were included in the evaluation of alternatives.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY OF P G PARA

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT AND

CITY OF TALLAHASSEE

DOCKET NO. 060635

NOVEMBER 21, 2006

Q. Please state your name and business address.

A. My name is P G Para. My business address is 21 West Church Street, Jacksonville, Florida 32202.

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

A. I am employed by JEA as Director, Legislative Affairs.

Q. Please describe your responsibilities in that position.

A. I am responsible for managing state and federal legislative and regulatory issues that may have an impact on JEA operations. My team is the primary contact between JEA and federal and state government bodies in the development of public policy affecting JEA interests.

Q. Please state your educational background and professional experience.

A. I graduated from Georgia Tech in 1972 with a Bachelors degree in Industrial Engineering and from the University of North Florida in 1985 with a Master of Business Administration. I am a Registered Professional Engineer in the State of Florida.

I have been with JEA since 1981, serving in load forecasting, as an engineer in generation, transmission and distribution planning, as manager of Electric System Planning, director of Fuels Management, and director of Legislative Affairs.

While manager of System Planning, I was responsible for generation, transmission and distribution planning, and load and energy forecasting. In addition, I was responsible for planning DSM programs and working with the Commission in JEA's conservation goals docket.

I have testified before the Commission on several occasions including in JEA's conservation goals docket.

Q. Have you reviewed the pre-filed testimony of Hale Powell that was filed on November 2, 2006?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut Mr. Powell's assertion that "a uniform methodology" should be used by all applicants in evaluating DSM cost-effectiveness.

I also will rebut Mr. Powell's suggestion that the Commission adopt new, albeit unspecified, criteria for evaluating DSM cost-effectiveness.

Q. Are you familiar with the Commission's practice in assessing how JEA and other electric utilities evaluate DSM cost-effectiveness?

A. Yes. As noted above, from 1993 through 1995 I was involved in the consolidated proceedings in which the Commission approved DSM goals for municipal and cooperative electric utilities that are subject to the Florida Energy Efficiency and Conservation Act (FEECA), Sections 366.80-366.85 and 403.519, Florida Statutes. At the conclusion of those proceedings, in Order No. PSC-95-0461-FOF-EG, at p.2 (Apr. 10, 1995), the Commission determined that the Rate Impact (RIM) test is appropriate for evaluating the cost-effectiveness of DSM measures. This conclusion was consistent with the Commission's earlier finding in Order No. PSC-94-1313-FOF-EG, at p.22 (Oct. 25, 1994), that the RIM test was appropriate for use in evaluating the cost-effectiveness of DSM measures for investor-owned utilities because the RIM test results in lower rates and ensures that customers who participate in a utility DSM measure are not subsidized by customers who do not participate.

Since 1995, the Commission has consistently relied upon the RIM test to evaluate and approve JEA's DSM goals. When JEA's current DSM plan was approved in 2004, for example, the Commission specifically found that "JEA appropriately evaluated the cost-effectiveness of measures using the RIM test." Order No. PSC-04-0768-PAA-EG, at p.2 (Aug. 9, 2004). It is my understanding that the Commission also continues to rely upon the RIM test to evaluate the cost-effectiveness of DSM plans for other electric

utilities subject to FEECA. Moreover, as further discussed in the rebuttal testimony of Bradley E. Kushner, the Commission relies on the RIM test (or DSM plans established based on the RIM test) for evaluating DSM measures in need determination proceedings.

Q. Mr. Powell notes in his testimony that JEA and the City of Tallahassee used different methodologies for assessing DSM measures in this proceeding. Do you agree with Mr. Powell's suggestion that the TEC Participants must use a "uniform methodology" to evaluate DSM cost-effectiveness?

A. No. In the consolidated 1995 proceedings I discussed previously, the Commission specifically recognized that all the municipal and cooperative utilities, with the exception of Tallahassee, used the RIM test to evaluate DSM cost-effectiveness. While Tallahassee proposed more measures than were cost-effective under the RIM test, the Commission recognized that because it does not have rate-setting authority over municipal and cooperative utilities, those utilities should have the latitude to adopt goals they deem appropriate regardless of cost-effectiveness. Order No. PSC-95-0461-FOF-EG, at p.2 (Apr. 10, 1995). In other words, although the Commission found the RIM test to be appropriate, the Commission recognized the City of Tallahassee's discretion to use a different methodology in establishing its DSM goals. Because the Commission does not have rate-making authority over the applicants in this case, there is no reason to reach a different conclusion in this proceeding.

Q. Do you agree with Mr. Powell's suggestion that the Commission adopt a new methodology or new criteria for assessing DSM cost-effectiveness in this proceeding?

A. No. First, Mr. Powell does not offer any particular methodology or present any evidence on how the Commission would implement a new methodology. He merely provides excerpts from a report assessing the DSM performance of a non-Florida utility. More importantly, however, adoption of a new methodology or new criteria for evaluating DSM cost-effectiveness would have broad ramifications for municipal, cooperative and investor-owned utilities throughout Florida in setting numeric DSM goals and in need determination proceedings. For that reason, this docket is not the appropriate forum to raise generic questions regarding how to evaluate the cost-effectiveness of DSM programs. Any revisions to the Commission's established methodology would be more appropriately addressed in a rulemaking or other generic proceeding in which all affected parties would have the opportunity to participate.

Q. Does this conclude your rebuttal testimony?

A. Yes.

CHAIRMAN EDGAR: Any other procedural type matters that we are in a position to be able to address now?

MS. BROWNLESS: Are we putting Mr. Fetter on today, Your Honor?

CHAIRMAN EDGAR: Thank you. Yes, we can do that.

MS. BROWNLESS: And we have copies of our exhibits, ma'am.

CHAIRMAN EDGAR: Okay. Oh, good. Okay. Is there any objection to calling witness Fetter at this time? No. Okay.

MS. RAEPPLE: All right. Steven Fetter.

Thereupon,

STEVEN M. FETTER

was called as a witness and, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MS. RAEPPLE:

Q. State your name and business address, please.

A. Steven M. Fetter, 1489 West Warm Springs Road, Suite 110, Henderson, Nevada, 89014.

Q. Have you been sworn?

A. Yes, I have been.

Q. Did you submit prefiled testimony on

September 19, 2006, in this proceeding consisting of seven pages?

A. Yes, I did.

Q. Do you have any changes or additions to your testimony?

A. No, I do not.

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

A. Yes, they would.

Q. Are you sponsoring any exhibits to your testimony?

A. One exhibit, SMF Number 1, my resumé.

Q. Which is Exhibit Number 59. Do you have any changes to that exhibit?

A. I believe my -- the e-mail address on the resumé, it has changed. It should read now regunf@gmail.com.

MS. RAEPPLE: Thank you. Madam Chairman, I request that Mr. Fetter's testimony be inserted into the record as though read.

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

BY MS. RAEPPLE:

Q. Have you prepared a summary of your testimony?

A. Yes, I have.

Q. Would you please present that summary?

A. Yes, I will.

Based upon my experience as chairman of a state public utility commission, head of the utility ratings practice at a major credit rating agency, and consultant to utilities, commissions, and consumer advocates, I offer my view that the Florida Public Service Commission in its consideration of the need for the coal-fired Taylor Energy Center should give significant weight to the benefits gained through the addition of generating facilities that enhance the diversity of fuels utilized within the state.

Fuel diversity refers to an electric utility's procurement of power supply encompassing a range of types of electric generation facilities, fuel sources, or purchased power agreements. Fuel diversification allows a utility to minimize the risks that accompany its operations and enable it to withstand the up and downs that are unanticipated specifically, but certainly foreseeable generally. Such risks include fuel price and supply volatility and price and supply effects from international political events, regional weather patterns, or unforeseen events. Basically, fuel diversity supports the mitigation of price and supply

risks and the achievement of an appropriate level of reliability and service quality for a utility and its customers on an ongoing basis.

Analysis of the framework of the Taylor Energy Center shows that the proposed project would be an effective means of meeting the state's growing power supply needs, while diversifying fuel use in a way that reduces supply and price volatility and overall risk for the utilities and their customers.

Thank you.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY OF STEVEN M. FETTER

ON BEHALF OF

FLORIDA MUNICIPAL POWER AGENCY

JEA

REEDY CREEK IMPROVEMENT DISTRICT

AND

CITY OF TALLAHASSEE

DOCKET NO. _____

SEPTEMBER 19, 2006

Q. Please state your name, title, and business address.

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

Q. On whose behalf are you testifying?

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

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

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

Q. What is your educational background?

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

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

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

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

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

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

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

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

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

A. My experience as Chairman and Commissioner on the Michigan PSC and my subsequent professional experience analyzing the U.S. investor owned and municipal electric and natural gas sectors from a credit rating perspective – in jurisdictions involved in restructuring activity as well as those still following a traditional regulated path – have given me solid insight into the importance of fuel diversity for generating facilities, both for internal utility operations as well as for how electric utilities are viewed by the financial community. Fuel

diversity related to power supply, whether internally generated or procured through power purchases, is a factor that enters into the process of utility credit analysis and formulation of individual company credit ratings.

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

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

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

Q. What is the purpose of your testimony?

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

Q. What is fuel diversity?

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

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

A. Yes. Fuel diversification allows a utility to minimize the risks that accompany its operations and enable it to withstand the ups and downs that are unanticipated specifically, but certainly foreseeable generally. Such risks

include fuel price and supply volatility and price and supply effects from international political events or regional weather patterns or unforeseen events. Basically, fuel diversity supports the mitigation of price and supply risks and the achievement of an appropriate level of reliability and service quality for a utility and its customers on an ongoing basis.

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

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

Q. Do you have concluding thoughts?

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

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

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

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

Q. Does this conclude your direct testimony?

A. Yes.

MS. RAEPPLE: Tender the witness for cross-examination.

CHAIRMAN EDGAR: Thank you. Mr. Simms.

MR. SIMMS: Thank you, Madam Chairman.

CROSS-EXAMINATION

BY MR. SIMMS:

Q. Just a few questions. Good evening, Mr. Fetter.

A. Hello, Mr. Simms.

Q. In your testimony, you describe yourself as an advisor to the utility industry based on your financial, regulatory, legislative, and legal experience. And I believe that appears in your testimony, or language to that effect, at page 3, lines 9 through 10. Just recognizing that that's a description of your background; is that right?

A. That is the description.

Q. And your testimony in this proceeding relates primarily to fuel diversity, and in particular, the addition of coal as a fuel resource; is that right?

A. Well, I talk about fuel diversity generally and indicate that the coal-fired Taylor Energy Center would increase the diversity of the participants to the project.

Q. Okay. So your testimony in this proceeding is

that the addition of coal is a positive benefit for these participants?

A. Yes. It increases the diversity and the positive benefits that come with a more diverse portfolio of supply.

Q. And as a consultant in the energy regulatory field and based on your broad experience, are you generally familiar with issues regarding costs associated with the possible regulation of CO_2?

A. I've followed it over the last several years at the federal level waiting for action to be taken.

Q. In your professional opinion, do you agree in general that regulation of CO_2 is likely to have the greatest impact on coal-fired power plants?

A. Well, it's hard to tell what the future holds with regard to legislative activity. Certainly at the federal level, where right now the White House is held by one party and the Congress is held by another, I don't expect a lot of positive movement on legislation based on that situation.

Q. Excuse me. I understand. That's really not the question. I'm not asking you about the likelihood of CO_2 regulation. My question is really getting at, if there is CO_2 regulation, are coal-fired power plants subject to the most exposure from a cost perspective?

A. Well, it would depend what the structure of any legislation was. And as I indicated, with the great differential between power within Washington, D.C. right now, it's hard to predict how any legislation, if it were to pass, would shape up.

Q. Okay. Were there CO_2 regulation, would you agree that coal-fired power plants are likely to have a greater cost exposure than, for example, natural gas or nuclear energy, specifically related to the regulation of CO_2?

A. As I said, it depends what the structure of any legislation would be. I would think coal would be -- do you want me to finish, or do you --

Q. Yes, please. I'm sorry.

A. -- want to interrupt?

Q. No. I'm sorry. Please finish.

A. I would expect coal to be more of a focus of potential legislation than nuclear or natural gas, but it's hard to see how the structure of any legislation would be done.

Q. So you're suggesting that it would be feasible to have a regulatory structure for CO_2 emissions that would create a greater cost exposure to a natural gas plant than to a coal plant?

A. You said I see it as feasible?

Q. Yes.

A. As I said, I think it's going to be very difficult for legislation related to the subject area to pass.

Q. That wasn't my question. I'm sorry. I'm asking about the degree of potential cost exposure between a coal plant, for example, and a natural gas plant. And as I understand your answer, you're telling me that it is feasible that a CO_2 regulatory framework could be established that would create a greater cost exposure for a natural gas plant than it would for a coal plant. Is that what you're saying?

A. And that's why the cost participants did a scenario which factored in the potential for such legislation.

Q. I understand what you're saying, and it's not answering the question that I'm asking, which is, as between coal plants and natural gas plants, which is going to have more cost exposure when it comes to CO_2 regulation?

A. And I would say it depends on the structure of the legislation.

Q. And my response is, so you're saying that it would be possible to structure regulation of CO_2 that would be more costly for natural gas plants than it

would be for coal plants? Just a yes or no answer to that question is what I'm looking for.

A. Well, if you don't let -- you earlier asked if it would be greater exposure for coal versus natural gas, and now you've flipped it and said I'm saying that it would be greater exposure for natural gas versus coal. And there is a midpoint in there where, depending on how the legislation is structured, it might be a wash on how those plants are treated.

Q. I see. So your position is that CO_2 regulation could be enacted that would have the same effect for a similar megawatt size power production on a coal plant and a natural gas plant?

A. I guess my view, the greater likelihood is that legislation won't pass, which means it would be a wash on both types of plants.

MR. SIMMS: Okay. It seems like I'm not going to get an answer to the questions that I'm asking, so I will pass along to the next interviewer.

CHAIRMAN EDGAR: Okay. Ms. Paben?

Mr. Jacobs.

MR. JACOBS: Thank you, Madam Chair.

CROSS-EXAMINATION

BY MR. JACOBS:

Q. Good afternoon, Mr. Fetter.

A. Hello, Mr. Jacobs.

Q. In your analysis, you based your conclusions on the fuel price projections that were acquired from Hill & Associates on behalf of the applicants?

A. I'm sorry. Could you ask the question again, Mr. Jacobs?

Q. Your analysis with regard to the preferable -- strike that. Your analysis as to fuel diversity and its benefits in this particular case, did you base that on the fuel projections that were done by Hill & Associates on behalf of the applicants?

A. Well, my testimony is based on the benefits of fuel diversity. I leave it to Mr. Preston to defend the positive impact of his fuel forecasts.

Q. I see. So you're speaking from a more generic nature, that it's beneficial to have fuel diversity?

A. I'm speaking from an operational basis for utilities, and also from the view of the financial community, that they view that greater fuel diversity results in minimization of risks of utility operations.

Q. Are you aware and would you recognize that there would be some accountability to that fuel diversity; i.e., is there a measure of cost-effectiveness that you would apply to fuel diversity?

A. By cost-effectiveness -- the project participants have put forward their case that their project is cost-effective, and so to the extent that it's cost-effective, then my fuel diversity views are beneficial.

Q. I see. So then to the extent that the data that supports the parties' determination of cost-effectiveness are upheld, then your views as to fuel diversity would follow; is that a fair statement?

A. They would. And putting on my old regulatory hat, I viewed my regulatory charge as making a judgment whether the parties' behavior fell within a range of reasonable action, and that is how I view this Commission should appropriately look at the case that's being put forward.

Q. Now, are you aware that in this case, one of the fundamental elements justifying fuel diversity is the volatility in natural gas prices? Is that your understanding?

A. Yes. There has been great volatility in natural gas prices, and I would expect that that would continue based on the nature of the natural gas process and also, as I said in my summary, unforeseen events, which we cannot predict with specificity today, but which, as we certainly saw in the last year or two,

things could happen that no one could have ever predicted.

Q. And so you would not -- let me make sure I ask my question correctly. Let me be specific. Are you aware in this case of the projections that natural gas prices could moderate downward over the course of the planning cycle for this plant?

A. I've reviewed the participants' testimony in this case generally. I have not looked at it with great specificity.

Q. Okay. Now, let me ask you this. Are you aware of the volatility in the coal market, commodity coal markets?

A. My understanding from my 20 years of experience is that any volatility in the coal markets would be less pronounced than within the natural gas markets.

Q. And so based on that, you would not perceive that there would be a need for diversity away from coal based on that rationale? In other words, you would not recommend the parties would need a diversity strategy that takes them away from coal, because you believe the volatility is lessened in that market.

A. Well, if I was testifying for utilities that had 90 percent coal or 95 percent coal, I would testify

that greater fuel diversity away from coal would be beneficial. But that's not the situation here. Here's heavily natural gas. Some of the utilities have heavy involvement in purchased power agreements. And so I view their movement away from that predominance of natural gas, and for the utilities that have heavy purchased power involvement, I view it as a positive, the direction they're going.

Q. I want to be as precise as I can. I'm trying to get to the point of, you would invoke the idea of fuel diversity as a reasonable strategy based on whether or not somebody is heavily weighted in one fuel or not or whether or not there's volatility in that fuel market or not?

A. Well, certainly your first comment, as I said, you know, I would recommend moving away from coal if that was heavily predominant among a utility's operations. At the same time, natural gas I view as more volatile than the coal markets. But even with that statement, if a company was 95 percent coal, I would encourage it, recommend that it move towards some degree of natural gas, notwithstanding the greater volatility within the natural gas markets.

Q. Okay. Let's stay with the scenario in this matter. If we agree -- and we'll set that as an aside.

If we agree that there is a heavy preponderance of natural gas transmission and the goal would be to diversify away, in your analysis, that would be the preferred option even if the choice is coal and even if that coal market has volatility in and of itself?

A. Yes.

MR. JACOBS: Okay. Do you -- one moment. I may be able to conclude, Madam Chair.

Thank you.

THE WITNESS: Thank you, Mr. Jacobs.

CHAIRMAN EDGAR: Are there questions from staff?

MS. FLEMING: No questions.

CHAIRMAN EDGAR: Thank you.

MS. RAEPPLE: No redirect.

CHAIRMAN EDGAR: No redirect? Okay. We have an exhibit.

MS. RAEPPLE: We, yes, we do. We have Exhibit 59. We move that exhibit into the record, please.

CHAIRMAN EDGAR: Okay. Exhibit 59 will be entered into the record with the correction that the witness put on the record.

(Exhibit Number 59 was admitted into evidence.)

CHAIRMAN EDGAR: Thank you. You're excused.

Thank very much, and thank you for your patience today.

MS. RAEPPLE: Madam Chairman, there is one more witness who I understand from the attorneys for the intervenors they have just a very few questions that we might be able to get done yet today if you are up to staying a little bit.

CHAIRMAN EDGAR: Which witness is that?

MS. RAEPPLE: Don Gilbert.

MS. BROWNLESS: No, we have several questions for Mr. Gilbert. We have extensive questions for Mr. Gilbert.

CHAIRMAN EDGAR: Okay. I appreciate the suggestion.

MS. RAEPPLE: Oh, well, I misunderstood on the break.

MR. JACOBS: We spoke, and I had not conferred, so that was my error.

MS. RAEPPLE: I thought she was in on the discussion. I apologize.

CHAIRMAN EDGAR: That's okay. I appreciate the suggestion, and I understand the response.

And again, thank you, everybody, for your patience, but I think it's about time to call it a day. Ms. Brubaker, anything else we need to do, should do, could do, can do today without going into another

witness?

MS. BRUBAKER: I'm not aware of anything else that needs attention at this time.

CHAIRMAN EDGAR: All right. Again, we have a lot of work to do tomorrow. I again request, as I know we will have, participation and cooperation so that we can work through it all together and do what we need today. And we will be back at 9:30 tomorrow morning. We are on break until tomorrow.

(Proceedings recessed at 5:32 p.m.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA:

COUNTY OF LEON:

I, MARY ALLEN NEEL, Registered Professional Reporter, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter translated under my supervision; and the foregoing pages numbered 514 through 641 are a true and correct record of the aforesaid proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor relative or employee of such attorney or counsel, or financially interested in the foregoing action.

DATED THIS 12th day of January, 2007.

MARY ALLEN NEEL, RPR, FPR
2894-A Remington Green Lane
Tallahassee, Florida 32308
(850) 878-2221