BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070098-EI

In the Matter of:

PETITION FOR DETERMINATION OF NEED FOR GLADES POWER PARK UNITS 1 AND 2 ELECTRICAL POWER PLANTS IN GLADES COUNTY, BY FLORIDA POWER & LIGHT COMPANY.
_______________________________________/

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VOLUME 4

Pages 458 through 651

PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN LISA POLAK EDGAR COMMISSIONER MATTHEW M. CARTER, II COMMISSIONER KATRINA J. McMURRIAN
DATE:	Tuesday, April 17, 2007
TIME:	Commenced at 9:30 a.m. Recessed at 5:52 p.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

EXHIBITS

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P R O C E E D I N G S

(Transcript follows in sequence from Volume 4.)

CHAIRMAN EDGAR: Okay. We are going to get started again. I hope everybody had a lovely lunch.

Before we call the next witness, do we have any housekeeping items?

MR. GROSS: Madam Chair.

CHAIRMAN EDGAR: Mr. Gross.

MR. GROSS: The question of whether or not Mr. David Schlissel can testify today has reached an impasse. In terms of the parties trying to work it out, FPL and Sierra Club, NRDC, et al., have reached an impasse.

I just want to kind of tell you our side of the story, which is that at the prehearing conference on March 30th, I raised the point that Mr. Schlissel and Mr. Plunkett could only testify today. And there was a reference to it, but with a little caveat. There was no commitment in the Prehearing Order guaranteeing that they would be able to testify, but only if the flow of the proceedings permitted it. So I raised it again as a preliminary matter for this hearing.

And as you know, there was a lot of bad weather up north, and I was in constant contact --

Mr. Plunkett is from Bristol, Vermont, and Mr. Schlissel is from Cambridge, Massachusetts. They both ran into problems with delayed flights getting out, and Mr. Schlissel was --

CHAIRMAN EDGAR: Okay. Mr. Gross, let me -- just in the interest of time, what is the availability of these two gentleman?

MR. GROSS: Okay. Mr. Schlissel is available today. He cannot come back next week. Mr. Plunkett, I told him to turn around and go home if he could come back next week, and he said he can come back next week, so I said -- he was on his way driving here. I mean, he had flown most of the distance, but there was one leg that he was going to drive.

CHAIRMAN EDGAR: So Mr. Schlissel -- I'm sorry. You're going to have to help me with that one. Schlissel --

MR. GROSS: Right.

CHAIRMAN EDGAR: -- is available this afternoon, but is not available next week.

MR. GROSS: That's right.

CHAIRMAN EDGAR: Mr. Litchfield, do you have objection to us taking Mr. Schlissel out of order?

MR. LITCHFIELD: We do, Madam Chairman. We have -- Mr. Brandt is next up, and he's back by

Ms. Grealy here, and he's ready to go. He's got scheduling difficulties next week, and we would like to get him on and off today, including with his rebuttal.

We have Mr. Seth Schwartz, who is not available at all next week. He in fact will be out of the country, off of the continent, so he would be next up in our proposed order, and he also would take up his direct and rebuttal at the same time.

Mr. Jenkins has scheduling difficulties. We would propose him as third, but we could work around him.

My issue is, I have enough cross for Mr. Schlissel to take up a fair amount of the afternoon and would not want to start him late in the day. The offer that I have made to counsel is that we could perhaps allow Mr. Schlissel to dial in by telephone, which I know from time to time has been undertaken by this Commission. And I don't think I had any objections from any of the other parties on that point.

I would note, however, with respect to the schedule this week, we went through a lot of testimony yesterday from various constituents represented here by counsel and were not able to get started early enough. And so to that point as well, we've got scheduling issues as well. We would like to proceed with

Mr. Brandt and then Mr. Schwartz.

Now, if we had time to do Mr. Schlissel today, you know, we could undertake that. I just did not want to suggest to Mr -- except I wouldn't finish, Madam Chairman. I would not finish with Mr. Schlissel today. So I think the best part of valor would be to take him by telephone, and we would be amenable to any scheduled point at next week's hearing to take that up if that's acceptable.

CHAIRMAN EDGAR: With all due respect, not completely, Mr. Litchfield. I am not completely comfortable with telephone participation. Now, we may be able to work something out. We do, I understand, have depositions and interrogatories and other sworn testimony that was taken as part of the preparation for this proceeding.

I did say very early on yesterday, and I don't recall the time, but at some point early in our proceeding yesterday, requested all parties to work together as far as scheduling and that I am, as always, amenable to taking parties out of order with notice so that all parties who would like to avail themselves of the opportunity for cross have notice to do that, no surprises. We do not spring surprises on people here anyway. But we did have part of a day yesterday, we've had all day today, and we've got two days with notice next week. You know, I've been rescheduling meetings, and I know that my colleagues have and our staff have. And again, we're not trying to single out any one person, party, witness, or whatever. I want us to conduct the business that we need to do, as I said yesterday, as thoroughly and efficiently as we can.

Telephone cross is just as somewhat unworkable, quite frankly. So we have this afternoon, we have Wednesday, and we have Thursday. I, as I said a moment ago, am amenable if we can work it out, and I will look to our staff for assistance with that. If indeed we can either stipulate a witness, and/or with that, enter deposition testimony, that seems to me as one perhaps workable item.

Now, just that so I am clear, Mr. Litchfield, you have said that you have witness Brandt and witness Schwartz, who are available today, but may not be next week, and Mr. Jenkins potentially.

MR. LITCHFIELD: Mr. Jenkins would prefer because of scheduling difficulties to go today, but we recognize that that may not be possible, so he is willing to make adjustments if necessary.

CHAIRMAN EDGAR: Is Mr. Jenkins a witness that could potentially be stipulated?

MR. GROSS: He happens --

CHAIRMAN EDGAR: I'm hearing no from the aura around you. Okay. It was a fair question, and I got an answer. Okay. So no stip for Mr. Jenkins.

And, Mr. Litchfield, you said that you have a significant amount of questions for Mr. Schlissel, and I realize that it is sometimes difficult to quantify a period of time. But if we all work together, can you give me an estimate?

MR. LITCHFIELD: Well, obviously, it depends on the witness. My experience in the deposition suggests to me that it will take longer than I would care to take, but at this point, my best guess is that I have about an hour and a half, maybe two.

CHAIRMAN EDGAR: It looks to me like it may be an hour or depositions.

MR. LITCHFIELD: You mean entering the deposition in lieu of cross-examination?

CHAIRMAN EDGAR: I'm throwing that out as a possibility, yes.

MR. GROSS: Madam Chair, we're not prepared to use -- if you're referring to Mr. Schlissel's deposition, that is -- we're not prepared to accept that proposal at this time. We would like Mr. Schlissel to testify live. We only have three total witnesses. I believe we stipulated to four FPL witnesses. There were 11 witnesses who were testifying.

And I feel compelled to clarify something. None of those constituents were brought here by my clients.

CHAIRMAN EDGAR: I understand.

MR. GROSS: They came on their own.

CHAIRMAN EDGAR: And I think Mr. Litchfield was probably referring to Mr. Beck. But regardless, I understand your point. Mr. Beck is staying out of this scheduling discussion.

Okay. How about if we do this. How about if we take up Mr. Brandt and then we go to Mr. Schlissel, realizing that that puts us in perhaps a dilemma with Mr. Schwartz. Is that -- am I getting my witnesses confused, the availability, that is?

MR. LITCHFIELD: We would really need to go with Mr. Schwartz next, because he literally will be off the continent next week.

CHAIRMAN EDGAR: Okay. Then I was confusing the logistics there.

Mr. Gross, do you have any objection, and Mr. Beck and Mr. Krasowski, of course, if we take up witness Schwartz, and then we go to Schlissel, and we see where we are from that point? And I'm going to ask all of you to try to, quite frankly, keep your questioning efficient.

Mr. Litchfield.

MR. LITCHFIELD: I'm sorry. Were we going about Mr. Brandt first or Mr. Schwartz first?

CHAIRMAN EDGAR: I thought your suggestion was Schwartz.

MR. LITCHFIELD: Well, my suggestion was certainly Schwartz in front of Schlissel, given that he'll be off the continent, but we had hoped to also have Mr. Brandt go today, to be on and off.

CHAIRMAN EDGAR: Well, we have until 5:30.

MR. LITCHFIELD: Okay. Fair enough.

CHAIRMAN EDGAR: So with that understanding, then Mr. Litchfield, it is your witness, and I will leave it to you as to whether it is Brandt or Schwartz.

MR. LITCHFIELD: It will be Mr. Schwartz. Thank you.

CHAIRMAN EDGAR: Okay.

MR. KRASOWSKI: Madam Chair.

CHAIRMAN EDGAR: Mr. Krasowski, yes.

MR. KRASOWSKI: We have a very, very strong interest in a lot of questions for Mr. Brandt, and he's scheduled to go next. I don't know if the whole day is going to be taken up with Mr. Schwartz. We could.

We're very flexible, though, otherwise.

CHAIRMAN EDGAR: And I appreciate that more than you know. I'm trying to be flexible as well.

MR. KRASOWSKI: Well, we don't want to complicate what you're doing, and we're here whenever you want us to be.

CHAIRMAN EDGAR: Thank you.

MR. KRASOWSKI: But we don't want to miss opportunities. But if it's necessary for Mr. Schwartz to go first, but either way.

CHAIRMAN EDGAR: Can you work with us if we go with Schwartz first?

MR. KRASOWSKI: Yes, I can.

CHAIRMAN EDGAR: Okay. Well, let's try that. And, again, efficient, concise, effective questions and answers make for efficient and effective recommendations.

MR. GROSS: Madam Chair.

CHAIRMAN EDGAR: Mr. Gross.

MR. GROSS: I've just been informed that Mr. Schlissel has a 4:30 flight, and that's why we were hoping to be able to get him in before that time.

Oh, it's a 5:30 flight, but he has to leave -- he needs some lead time.

CHAIRMAN EDGAR: Sure. If we would, please, all, welcome, please realize that I'm trying to work with all of you and the scheduling restraints that we have. Duly noted, and we'll do the best we can. But quite frankly, that's really more in all of your hands than it is in mine, although I will make every effort to attempt to keep us moving.

And with that, Ms. Smith, we will need to swear in your witness.

MS. SMITH: Yes, Mr. Schwartz.

CHAIRMAN EDGAR: Mr. Schwartz, if you would, stand with me and raise your right hand.

Thereupon,

SETH SCHWARTZ

was called as a witness on behalf of Florida Power & Light Company, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MS. SMITH:

Q. Would you please state your name and business address?

A. My name is Seth Schwartz. My business address is 1901 North Moore Street, Arlington, Virginia 22209.

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

A. I'm employed by Energy Ventures Analysis, Inc., and I'm a principal in the firm.

Q. Have you prepared and caused to be filed 33 pages of prefiled direct testimony in this proceeding?

A. Yes.

Q. Do you have any changes or revisions to your prefiled direct testimony?

A. No.

Q. If I asked you the same questions contained in your prefiled direct testimony, would your answers be the same?

A. Yes.

MS. SMITH: I would ask that Mr. Schwartz's prefiled direct testimony be inserted into the record as though read.

CHAIRMAN EDGAR: The prefiled direct testimony will be entered into the record as though read. And before we go further, may I ask about the redirect? I know at one point, there had been a desire to take them up separately. However, there has been some discussion about taking them up together in the interest of time. Do we have a consensus on that?

MS. SMITH: We're planning to do Mr. Schwartz's direct and rebuttal appearance.

CHAIRMAN EDGAR: Mr. Gross, can you work with that, and to the other intervenors as well?

MR. GROSS: Madam Chair, yes.

CHAIRMAN EDGAR: I'm seeing nods across the board. Okay. Then we will do the rebuttal as well.

BY MS. SMITH:

Q. Mr. Schwartz, are you also sponsoring any exhibits to your direct testimony?

A. Yes, I am.

Q. And do those exhibits consist of documents SS-1 through SS-20?

A. Yes.

MS. SMITH: And those exhibits have been premarked for identification as 73 through 92.

CHAIRMAN EDGAR: Thank you.

BY MS. SMITH:

Q. Mr. Schwartz, have you prepared and caused to be filed 15 pages of prefiled rebuttal testimony in this proceeding?

A. Yes.

Q. Do you have any changes or revisions to your prefiled rebuttal testimony?

A. No.

Q. If I asked you the same questions contained in your prefiled rebuttal testimony today, would your answers be the same?

A. Yes, they would.

MS. SMITH: I ask that Mr. Schwartz's prefiled rebuttal testimony be inserted into the record as though read.

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

BY MS. SMITH:

Q. Mr. Schwartz, are you also sponsoring any exhibits to your rebuttal testimony?

A. Yes.

Q. And do those exhibits consist of documents SS-21 through SS-32?

A. Yes.

MS. SMITH: And, Madam Chairman, those have been premarked for identification as 135 through 146.

CHAIRMAN EDGAR: Thank you.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF SETH SCHWARTZ

DOCKET NO. 07____EI

JANUARY 29, 2007

Q. Please state your name and business address.

A. My name is Seth Schwartz. My business address is 1901 North Moore Street, Suite 1200, Arlington, Virginia 22209.

Q. By whom are you employed and what is your position?

A. I am employed by Energy Ventures Analysis, Inc. (EVA), where I am a principal.

Q. Please describe your duties and responsibilities in that position.

A. EVA is a consulting firm that engages in a variety of projects for private and public sector clients. These consulting projects are related to energy and environmental issues. In the energy area, much of our work is related to analysis of the electric utility industry, fuel markets, particularly coal, natural gas, oil, and petroleum coke, and the transportation thereof. Our clients in these areas include coal, oil and natural gas producers, electric utility and industrial energy consumers, and energy transporters. We also work for a number of public agencies, such as state regulatory commissions, the U.S. Environmental Protection Agency, and the U.S. Department of Energy, as well as intervenors in utility rate proceedings, such as consumer counsels and municipalities. Another group of clients include trade and industry associations, such as the Electric Power Research Institute, the Gas Research Institute and the Center for Energy and Economic Development. EVA has provided testimony to numerous state public utility commissions, including the Florida Public Service Commission. Furthermore, the firm has filed testimony in a number of cases in both state and federal courts, as well as before the Federal Energy Regulatory Commission.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science Degree in Geological Engineering from Princeton University in 1977. I was a founder of EVA in 1981, and have been a principal in the company since then. I perform and manage a variety of fuel-related consulting work for the electric utility industry, including fuel supply strategy studies, market analyses and price forecasts. I also audit the management and performance of electric utility fuel supply departments and provide testimony to public service commissions. My resume is attached as Document No. SS-1, page 1 and 2.

PURPOSE AND SUMMARY OF TESTIMONY

Q. Are you sponsoring an exhibit in this case?

A. Yes. I am sponsoring an exhibit, which consists of the following documents:

Document No. SS-1	Resume of Seth Schwartz
Document No. SS-2	Power Generation in Florida
Document No. SS-3	Changes in Fuel Prices since 1992

Document No. SS-4	U.S. Coal Industry Production
Document No. SS-5	Map of U.S. Coal Supply Regions
Document No. SS-6	U.S. Coal Demand by Sector
Document No. SS-7	U.S. Coal Imports
Document No. SS-8	U.S. Coal Pricing
Document No. SS-9	Central Appalachia Coal Production
Document No. SS-10	Central Appalachia Coal Demand by Sector
Document No. SS-11	Outlook for Central Appalachia Coal
Document No. SS-12	Central Appalachia Coal Reserves
Document No. SS-13	Central Appalachia Coal Production by Company
Document No. SS-14	Routings from Central Appalachia to FGPP
Document No. SS-15	Global Thermal Coal Trade
Document No. SS-16	Global Metallurgical Coal Trade
Document No. SS-17	Coking Capacity Additions
Document No. SS-18	Petroleum Coke Pricing
Document No. SS-19	FPL Fuel Price Forecast
Document No. SS-20	Comparisons of FGPP Delivered Price Forecasts

Q. **Are you sponsoring any sections of the Need Study in this proceeding?**

A. Yes. V.A.2.c (parts iii and iv) and I co-sponsor Appendix E of the Need Study.

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is to provide background information on the coal industry and to provide EVA's expert opinion on an assessment of the transportation strategy FPL is employing at the FPL Glades Power Park

(FGPP) and to affirm the reasonableness of the projected delivered costs and procurement strategy for coal and petroleum coke included in this application.

Q. Please provide an overview of the fuel supply for FGPP.

A. Like the other utilities in Florida, FPL's reliance on coal-based generation is less than the national average. FPL has ownership interests in two coal-fired plants, Scherer 4 and St. Johns River Power Park (SJRPP), which provided 5.2% of its energy sources in 2005. Historically, coal prices have displayed lower volatility than natural gas or oil prices. Even with its small ownership share, FPL's coal assets have helped to reduce fuel prices and fuel price volatility for FPL's customers. In my opinion, an expansion of its coal position with the addition of FGPP, should further reduce fuel prices and price volatility

FPL's decision to use 40 % Central Appalachia coal, 40 % imported coal and 20 % petroleum coke as its fueling plan for FGPP is reasonable. FPL will be able to adjust these ratios over time to purchase the lowest-cost combination of these fuels, reacting to changes in market prices. Historically, the price relationship between imported coal and Central Appalachia coal has varied due to changes in world markets. This plan will provide flexibility in sources of solid fuel, in order to achieve the lowest cost with reliable supplies.

The U.S. coal industry is undergoing a major shift as utility compliance with the Clean Air Interstate Rule will result in the retrofit of a significant number of scrubbers on power plants resulting in inter- and intra-regional switching of coal supplies. Demand for Central Appalachia coal overall will decline but Central Appalachia will remain a significant source of coal supply for utility plants in the southeastern U.S. to which it has a transportation advantage. Even in its diminished role, Central Appalachia has adequate coal reserves and will be a reliable source of supply for the life of the FGPP project.

Imports of coal into the U.S. will continue to grow as global coal trade expands with the continued development of export coal industries throughout the world. The largest source of import coal into the U.S. will be South America (Colombia and Venezuela) given its proximity. Since the mid 1980s when the U.S. started importing coal from South America, South America has been a reliable source of high quality bituminous coals. However, other sources, such as Russia, South Africa, Indonesia, and Australia coals are also possible sources of supply that can serve as alternatives to South American supplies when they are lower-cost, and provide reliability in the event that the primary sources of import coal are disrupted.

Petroleum coke supply is expected to expand over time as additional coking capacity is installed. Petroleum coke is a lower cost source of Btu's that many utilities have successfully incorporated into fuel supply as a means of controlling costs. The low volatile content of petroleum coke limits the extent to which it can be burned as part of the fuel blend.

The use of a portfolio strategy for fueling a power plant is consistent with best practices within the utility industry. A portfolio strategy consists of a combination of short, medium, and long term procurements which incorporate both supply and supplier diversification. By designing FGPP for a blend of Central Appalachia coal, import coal, and petroleum coke, FPL has a supply which incorporates three solid fuel sources but can swing supply as the market dictates subject to the technical limits for petroleum coke and contracting constraints on commitments for coal supply and transportation.

The delivered price forecast developed by FPL is reasonable and consistent with the delivered price forecast EVA prepared for Orlando Utilities Commission's new integrated gasification combined cycle (IGCC) plant at Stanton, to which I submitted testimony to the Florida Public Service Commission in the Need For Power application in February 2006.

FLORIDA ELECTRICITY GENERATION

Q. How do the sources of electric power generation in Florida compare to nationwide generation?

A. The sources of generation in 2005 by fuel type for Florida and the total U.S. are summarized on Document No. SS-2. Solid fuel (principally coal, but including petroleum coke) accounted for only 33% of total generation in Florida, compared to 52 % for the U.S. as a whole. Florida also had lower than the national shares for nuclear power generation and other (principally hydro power). As a result, Florida relied upon oil and natural gas for 52% of total generation in 2005, compared to only 20% for the U.S.

Q. What effect does this fuel mix have on Florida customers?

A. Florida customers are much more vulnerable to disruptions (both in price and reliability) than the average U.S. customer. The prices of oil and natural gas are historically much more volatile than the price of coal, as shown on Document No. SS-3. The increase in natural gas prices since 1992 has been 3 times the increase in coal prices over the same period (and up to 9 times the increase at the peak of natural gas prices in 2005). As experienced in the period 2004 to 2006, high prices for oil and natural gas have a major impact on electric power rates.

Q. What is FPL's supply of electric power by fuel type?

A. Because of its location in southern Florida, farthest from the U.S. coal fields, FPL has a lower share of coal-fired generation than the Florida average. In 2005, FPL supplied 5.2% of its power from coal (its ownership shares of Scherer 4 and SJRPP), 59.4% of its power from oil and natural gas, 19.2% from nuclear, and 16.0% from purchased power.

Q. How will FGPP affect FPL's generation by fuel source?

A. Based on FPL's 2006 Ten Year Power Plant Site Plan, the construction of FGPP will increase the share of coal (including petroleum coke) from 5.2% of FPL's power supply in 2005 to 14.4% in 2014.

Q. Will this increase in coal-fired generation benefit FPL's customers?

A. Yes. Diversifying the portfolio of generation sources will provide a more stable cost of electric generation for FPL, and reduce its exposure to disruptions in the oil and natural gas markets.

FUEL SUPPLY PLAN FOR FGPP

Q. What is FPL's fuel supply plan for FGPP?

A. FPL's fuel supply plan is to burn a blend of coals consisting of 40 % Central Appalachia coal, 40 % imported coal, and 20 % petroleum coke.

Q. What do you mean by FPL's fuel supply plan?

A. This is the mix of fuels for which FGPP would be designed and that FPL would expect to purchase over the long term. However, should the relative pricing of these products change, FPL will be able to adjust its fuel purchases to maximize the use of the least-cost combination of solid fuels subject to contractual limits.

Q. How does FPL's fuel supply plan for FGPP compare with the mix of solid fuels used by St. Johns River Power Park?

A. The mix of fuels used at SJRPP (20% owned by FPL) has been similar to the proposed plant for FGPP. In 2005, the fuel supply for SJRPP was 30% Central Appalachia coal, 52% imported coal, and 18% petroleum coke. This fuel supply plan has been very successful at SJRPP over the long term, providing both low cost and reliability.

Q. How does FPL's fuel supply plan compare with the mix of solid fuels currently used by Florida utilities?

A. In 2005, Florida utilities purchased over 25 million tons of solid fuels from three major coal supply regions plus petroleum coke. Central Appalachia coal accounted for over a third of the total purchases with the Illinois Basin and Imports not far behind. Petroleum coke accounted for 11 % of purchases on a tonnage basis. The other large supply regions, Northern Appalachia, Powder River Basin, and the Rockies accounted for a very small amount. In other words, FPL's plans are consistent with the fuel procurement of the other utilities in Florida.

Q. Please explain why FPL is not considering Illinois Basin coal for FGPP.

A. Although Illinois Basin coal is used by some of the coal-fired plants in Florida, this coal tends to be high in chlorine and is not compatible with the plant and scrubber design selected for FGPP.

Q. Is FPL's fuel supply plan for FGPP a good plan?

A. Yes, in several important respects. First, FPL has developed a fuel supply plan that is not dependent upon either a single coal supply region or a single coal within a coal supply region. Subject to meeting an average input sulfur content, FPL has considerable flexibility with respect to its solid fuel procurements. The ability to use coal from more than one supply region provides both security of supply as well as market competition. Second, FPL has incorporated petroleum coke into its plant design, permit, and fuel supply plan. Petroleum coke is an economic source of energy that has provided a number of utilities with an effective means of minimizing fuel costs. Third, FPL can receive coal from two rail carriers. As with multiple coal supply regions, multiple carriers provide both security of supply and competition.

US COAL INDUSTRY

Q. Please provide an overview of the U.S. coal industry.

A. In 2005, the U.S. coal industry produced over 1.1 billion tons of coal (Document No. SS-4). It is estimated that there is approximately 230 years of domestic coal reserves based on current demand. There are five major commercial producing coal regions in the U.S, of which the largest is the Powder River Basin. The largest coal supply region in the East is Central Appalachia, with Northern Appalachia and the Illinois Basin also major supplies to the commercial market. A map of the supply regions is provided in Document No. SS-5. Despite overall growth in U.S. coal production, demand for eastern coals has been declining as they have been displaced by western coals moving into eastern markets and by imported coal.

Most U.S. coal production is consumed domestically. The utility sector dwarfs all other sectors, accounting for almost 90 % of U.S. coal consumption (Document No. SS-6). The domestic metallurgical and industrial markets have declined over time with the collapse of the traditional steel industry and some loss of heavy industry. As a high cost producer of coal, the U.S. is now the swing exporter in the global coal market such that demand for U.S. coal increases when global supply is tight and falls when the market is in balance or there is a supply overhang.

Q. What role do imports play in the U.S.?

A. In 2005, electric generators imported over 23 million tons of coal (Document No. SS-7). Most of the coal went to coastal utilities which represent the most attractive market for imports due to the inland transportation savings.

Q. What is the outlook for U.S. coal demand?

A. U.S. demand for coal is expected to grow at an average annual rate of 1.3 % between 2006 and 2025 largely in response to the addition of almost 100 GW of new coal fired generating capacity. About 17 GW of new coal-fired capacity is expected to be added by the end of the decade, but much of the new capacity is expected to be added after 2010. The forecast assumes that this new generating capacity can be permitted and financed.

Q. What are the factors that affect the mix of coals burned by electric generators?

A. Utilities generally burn the coals which have the most favorable economics. The economics of the alternative coal supply regions have changed over time driven by three primary factors: environmental requirements, relative coal prices at the mine, and coal transportation costs.

Q. How have these factors affected FPL's fuel plan?

A. FPL's plan has selected the fuels likely to be the least-cost on a delivered basis. The selected fuels (Central Appalachia coal, imported coal, and petroleum coke) are the closest sources of solid fuel for FGPP, minimizing transportation costs, resulting in the most economic supply on a delivered basis.

Q. How have environmental requirements affected coal choice?

A. The Clean Air Act of 1970 and various amendments thereto have resulted in a variety of air pollution regulations which have limited the emissions of criteria pollutants including sulfur dioxide (SO_2). Utilities which have complied with regulations through the use of technology have more flexibility with respect to coal supply, not being limited to certain sulfur coals. Conversely, utilities which have complied through the use of low sulfur coals have been limited to low sulfur coals.

The most recent additions to these regulations are the 2005 Clean Air Interstate Rule (CAIR) and the 2005 Clean Air Mercury Rule (CAMR). Compliance with CAIR and CAMR will require the retrofit of many eastern power plants with flue gas desulfurization equipment (FGD) also known as scrubbers. These installations will enable utility coal buyers to reconsider coal supply options as sulfur content will no longer be as limiting a factor. The expected result of CAIR and CAMR compliance will be shifts both between and within supply regions to higher sulfur coals. Demand for Central Appalachia coals is expected to decline while demand for Northern Appalachia and Illinois Basin coals is expected to rise.

Q. How do environmental requirements affect FPL's fuel plan?

A. FPL is able to take advantage of the fact that the demand for lower-sulfur Central Appalachia coal is likely to fall, as customers in the Midwest retrofit control technologies and switch to higher-sulfur local coals. This will increase the availability of Central Appalachia coal at a lower price for FGPP, which will benefit from the fact that this is the closest domestic coal source, with the lowest transportation cost. By using this lower-sulfur coal, as well as lower-sulfur imported coal, FPL can blend low-cost, high-sulfur petroleum coke and still meet stringent emission limits.

Q. How do relative coal prices affect coal supply patterns?

A. Relative coal prices have also been important determinants of coal demand. It is not simply how much a particular coal costs, it is how much it costs compared to the alternatives.

Coal price formation is complex because coal is not a worldwide, or even a national, commodity. Rather coal operates as a set of overlapping regional commodities connected by the varying ability of customers to switch supply from one coal region to another. Within each coal supply region, coal functions like a commodity and long-term coal prices are set by the marginal cost of the production needed to satisfy demand.

Until 2000, coal prices had been relatively flat to declining on a nominal dollar basis as gains in mine productivity offset inflation-related increases. (Document No. SS-8) Low prices for Powder River Basin coals (PRB), particularly, made their use competitive in many eastern power plants designed for eastern coals.

In 2001 and again in 2004, eastern coal prices increased above historic levels, albeit for different reasons. The increase in pricing in 2001 was caused largely by inflated consumer stocks in 2000 which caused prices to fall as utilities stopped buying coal to return stocks to normal levels. The reduced purchasing led to mine closures such that when stocks were back to normal and purchasing resumed, the underlying supply was inadequate to meet demand and prices spiked. In 2004, eastern coal prices increased above historic levels when global demand for metallurgical coals caused some U.S. metallurgical coals that had been moving into the utility market to be diverted to the metallurgical coal market creating a shortfall of steam coal. The incremental demand tightened the demand supply balance and resulted in a price response.

While prices have fallen from their most recent peaks as a result of additional supply becoming available in response to higher prices and a return to better western rail performance, prices continue to be above historic levels as there has been a step increase in costs. In the east, costs have increased primarily as a result of lower mine productivity which has resulted from a slew of factors including worsening mine conditions as the better reserves are mined out, a tight labor situation with a declining pool of qualified miners, a more difficult regulatory environment, and higher prices which reduces management attention to costs. Higher commodity prices (oil, explosives, tires, etc.) have also increased mine costs. In the west, costs have increased as a result of declining mine productivity and higher mineral costs. The declining productivity reflects the higher ratios combined with the fact that the low-cost dragline capacity is already fully utilized, meaning the additional handling is using equipment with higher operating costs. Also, bonus payments for new mineral leases have increased substantially, requiring higher coal prices to obtain recovery of leasing costs.

Q. How do rail rates affect coal supply patterns?

A. Utilities do not decide which coals to buy based upon coal prices alone. Rather, they evaluate their coal choices on a delivered price basis. Two decades of declining rail rates (in constant dollars) intensified inter-regional coal competition and brought over 175 million tons of western coal to the east. Most of the western coal moving east was coal from the Powder River Basin which could compete with many eastern coals as a result of a low mine price and low rail rates. The best example is Georgia Power's Scherer station which consists of four units designed to burn low sulfur Central Appalachian coal. With the conversion of Scherer to Powder River Basin coal, this plant alone will account for about 14 million tons of Powder River Basin coal moving east.

New much higher western transportation rates may lead to different distribution patterns in the future. The rates now being quoted for movements are more than two times the rates in place when Georgia Power committed to convert Scherer to Powder River Basin coal. The rail system is not dissimilar to coal supply. Higher rates have increased railroad profitability which in turn has resulted in greater investment in the railroads in capacity expansions. As overall economic growth slows, the expansions will ease capacity and rates will fall, although unlikely to the low levels of the 1990's. As rail markets return to long-term price stability, we expect rail rates to average 50% - 100% more than the low rates which prevailed until 2003.

Q. How does FPL's fuel supply plan consider these factors which affect coal prices and transportation costs?

A. Because relative coal prices and freight rates vary over time, a fuel plan which allows flexibility in selecting coals from different supply regions will reduce costs over the long term. FPL's fuel plan provides for substantial flexibility in regional coal supply by developing multiple transportation options for delivery of coals from different supply regions, with competitive sources. This will allow FPL to adjust its fuel procurement decisions over time to minimize fuel costs.

Q. Given the prominence of the Powder River Basin, why is this coal not the design fuel for FGPP?

A. In the long-term, demand for Powder River Basin coals is expected to continue to increase as new power plants located in the West and Texas come on line. Over the last 10 years, much of the growth in demand for Powder River Basin coals has come from increasing capacity utilization of existing plants and displacement of others, particularly in eastern markets. Further displacement of eastern coals is unlikely as utility plants are retrofit with scrubbers and some of the displacement that has already occurred is likely to revert to eastern coals once scrubbers are retrofit. For new plants, the higher mine price for Powder River Basin coals combined with higher transportation costs makes it less economic in the eastern markets.

Q. Please provide an overview of the Central Appalachia coal supply region.

A. Central Appalachia includes coal production from eastern Kentucky, southern West Virginia, Virginia, and Tennessee. Central Appalachia is the largest coal supply region in the eastern U.S., although production has declined since 1990, as shown on Document No. SS-9.

Mining in Central Appalachia is somewhat different than mining in other coal supply regions given the nature of the reserves. The remaining reserve blocks in Central Appalachia are smaller and less conducive to either large surface mining operations (such as those in the Powder River Basin or lignite fields) or large underground mining operations (such as those in Northern Appalachia or the Rockies or under development in Illinois). The "typical" Central Appalachia operation is a facility consisting of a preparation plant/load out with several mines. The mines are generally small, i.e., less than two million tons per year of production, and have limited lives such that each mine typically has less than ten years of production. As a result, there is continuous need for new mine development and reserve acquisition in Central Appalachia.

Q. What is the market for Central Appalachia coal?

A. Central Appalachia's primary market is power generation, accounting for over 70 % of 2005 shipments, as shown on Document No. SS-10. Unlike other supply regions, substantial volumes move to other sectors as well including the domestic steel industry, other domestic industries and the export steam and metallurgical coal markets. The utility market consists of both power plants that were designed for Central Appalachia coals as well as power plants that switched to Central Appalachia coals in order to comply with Clean Air Act requirements.

Q. **What is the outlook for the demand for Central Appalachia coal?**

A. Most forecasts call for a decline in demand for Central Appalachia coal as utilities return to their design fuels with the retrofitting of scrubbers and imports continue to penetrate the coastal utilities.

EVA's most recent long-term forecast, which is provided in Document No. SS-11, calls for Central Appalachia coal demand to decline from 235.6 million tons in 2005 to about 173 million tons in 2020 and then hold steady. While the largest declines are projected for the utility sector due to fuel switching related to CAIR compliance and imports, declines in the other sectors are also forecast. Most notably, metallurgical coal exports are forecast to decline with the growth in overseas metallurgical coal supply.

Future utility demand for Central Appalachia coal includes a number of new coal-fired plants such as FGPP for which the logical coal supply is Central Appalachia. These plants are located primarily in the southeast, notably the Carolinas and Florida. Central Appalachia coal is the proximate source of supply and, in such cases, the economic source of supply. The decline in demand for Central Appalachia coal in other markets will increase the supply available for FPL and other customers in the southeast at economical prices.

Q. What is the outlook for the supply of Central Appalachia coal?

A. The Central Appalachia coal industry will contract in response to declining demand. Contraction in Central Appalachia may be somewhat easier than in other supply regions due to the nature of the supply. In other words, as the mines are depleted, some will not need to be replaced. Further, Central Appalachia has experienced recent production problems due to a variety of factors including reserve depletion, permitting, labor, and high production costs. As the supply contracts in response to declining demand, the pressures resulting from these problems on individual mines will lessen. For example, labor availability will improve.

Q. Are there adequate reserves to support Central Appalachia coal production at the 175 million ton per year level?

A. Yes. Reserve depletion is somewhat of a misnomer as significant Central Appalachia reserves remain. The coal producers will mine the lowest-cost reserves first and the mining conditions will steadily become more difficult over time. Reserve depletion has had a greater impact on production recently due to the depletion of the large reserve blocks that were the basis of the mines developed from old steel company properties in the last 15 to 20 years. As the steel company reserves are mined out, there are simply not comparable reserves to replace these mines. Nevertheless, substantial reserves remain. As shown on Document No. SS-12, the 10 publicly-traded coal companies in Central Appalachia (who accounted for 53 % of production in 2005) report almost five billion tons of controlled reserves as of the end of 2005, or 38 years of life at current production rates.

Q. What is the industry make up in Central Appalachia?

A. Central Appalachia is the least concentrated of any supply region. Looking at Central and Southern Appalachia combined; only two producers had markets shares greater than ten % in 2005 (Document No. SS-13). Consolidation within Central Appalachia is likely but the region is still likely to be less concentrated than other major supply regions. As a result, supply and pricing in Central Appalachia will continue to be very competitive.

Q. How would Central Appalachian coal move to FGPP?

A. The site has direct rail access to a short line railroad, the South Central Florida Express, which connects to both the CSXT Railroad (CSXT) and the Florida East Coast Railroad (FEC), which in turn connects to the Norfolk Southern Railroad (NS) at Jacksonville. The CSXT and NS are the two major rail carriers serving Central Appalachia, and provide access to all of the Central Appalachia reserves and production. The rail routings and connections to deliver this coal to FGPP are shown on Document No. SS-14.

Q. Considering all of these factors, is it likely that Central Appalachia coal will be an economic source of coal for FGPP?

A. Yes. FPL's plan maximizes competition for transportation of coal from this region, which is the closest source of coal for FGPP. This should minimize the delivered cost of coal and provide maximum flexibility and reliability of supply.

GLOBAL COAL INDUSTRY

Q. Please describe the global coal market.

A. The global coal market is best divided between thermal (steam) and metallurgical (coking) coal markets.

Global thermal coal trade has increased significantly in the last decade or so with the development of coal industries in South America and Indonesia and the expansion of the coal industries in Australia, Russia, and China (Document No. SS-15). On a tonnage basis, Indonesia surpassed Australia as the largest thermal coal exporter in 2004 and has additional expansion plans.

The thermal coal market is typically divided between the Atlantic and the Pacific with South American, South African and Russian coals dominating the Atlantic market and Australian and Indonesian coals dominating the Pacific market. With the large increased supply from the Pacific Rim, increasing volumes of Australian and Indonesian coals are moving into the Atlantic market and the distinction is lessening but will never disappear because of the difference in distances. The metallurgical coal market is smaller and fewer countries produce metallurgical grade coals (Document No. SS-16). The U.S. has retained a share of the European and South American markets. Australia is by far the largest exporter of metallurgical grade coals and accounts for over 50 % of the global market. Western Canada also produces high quality metallurgical coals which almost exclusively move to the Pacific Rim market.

The world's largest coal producer and consumer is China. In 2005, China is estimated to have produced 2.1 billion tons, over 95 % of which is consumed domestically. China produces both thermal and metallurgical coals. Despite China's relatively recent entrance into the global market, it is now a significant participant and the amount of coal it has available to export in any one year explains much of the recent volatility in global coal pricing. China also imports some coal which also affects the global market balance. In virtually all forecasts of global coal prices, the prognosticators state that China is the wild card. Higher exports can cause global pricing to fall; conversely lower exports can cause global pricing to increase.

Q. What are the primary sources of imported coal to Florida?

A. The primary source of steam coal imports to Florida is South American coal, because its proximity means that the delivered price is less than other imported coal sources. Colombia is the principal source of imported coal, but Venezuela also has an active coal industry.

Q. Please describe the Colombian coal industry.

A. Colombian coal is produced in three major coal fields. All of the coal from these reserves is bituminous. The mines are typically surface mines operating in multiple seams. Coal quality is good. While the heating content varies among the basins, it typically runs from 11,000 to 12,600 Btu per pound. The sulfur content is typically below 1.0 % and can run as low as 0.6 %. Ash is generally low. The coal is classified as a steam coal.

Colombian coal exports have grown significantly over the last decade. Exports exceeded 60 million tons in 2005 and are expected to continue to grow with the expansion of existing mine and development of new mines. Infrastructure investments are also underway with a May 2006 government commitment to a new export terminal in Santa Marta Bay.

Most of the coal produced in Colombia comes from two large mines: the Cerrejon mine and Mina Pribbenow. Cerrejon, owned by BHP-Billiton, Anglo American and Xstrata, produced 28 million tons in 2005. Mina Pribbenow, which is owned by Drummond, produced 24 million tons. The balance comes from two Glencore mines and a smattering of other small producers.

The Colombia coal is exported through several ports. The two main ports are Puerto Bolivar which handles the Cerrejon coal and Puerto Drummond which handles the Mina Pribbenow production. Most of the ports can accommodate all vessel types and sizes.

Colombia is reported to have 7.3 billion tons of recoverable reserves. The reserves are mostly high quality bituminous steam coal. At current or even expanded production levels, Colombia has well over 100 years of reserves. In addition, reserves of a like or greater amount are indicated and inferred which could double these estimates.

Q. **Please describe the Venezuelan coal industry.**

A. Venezuela, by contrast, is much smaller. In 2005, Venezuela exported under 10 million tons. Most reserves are in the western part of the country in the state of Zulia. Venezuelan coal is hotter than Colombian coal, typically 12,200 Btu per pound and above. Estimated recoverable reserves are about 0.5 billion tons.

Venezuelan coal moves primarily into the steam coal market although some has been successfully marketed as a PCI coal[1]. Venezuela coal exports move primarily to Europe and North America.

One mine accounts for most of Venezuela coal production. Carbones del Guasare's Paso Diablo mine, which is currently owned in varying %ages by the government, Anglo American, and Peabody, produced 6.3 million tons in 2005. The balance of Venezuela production comes from several small mines.

Coal production in Venezuela has been limited by infrastructure. Most of the coal is exported through Bulkwayuu, a storage and loading vessel on Lake Maracaibo. Vessel sizes at Bulkwayuu are limited to panamax. In order for exports from Venezuela to expand, significant investment in infrastructure must take place. The current political instability makes such investment questionable in the near term. However, even if not immediately, this

[1] Pulverized Coal Injection is the process by which some non-coking coal is added to coke ovens, reducing the metallurgical coal requirements.

investment is still likely such that over time Venezuelan coal exports can be expected to increase.

Q. What has the record of performance of these suppliers been?

A. Overall, performance has been good. In 2006, there was a labor dispute at Drummond's mine which disrupted production for about one month. Other than that and the occasional contract dispute, shipments from South America have been very reliable.

Q. Are there other potential sources of imports besides South America?

A. Yes. Coal imports are not limited to Colombia and Venezuela although they do clearly have a transportation advantage. As noted above, a number of other countries are large coal exporters, several of which also present potential sources of supply.

The closest, non-South American source is Russia, whose reserves are the second largest in the world. In recent years, Russia has become a major coal exporter into the Atlantic market. Europe is Russia's largest market although test quantities have moved across the Atlantic. The coal is good quality steam coal, high in Btu and low in sulfur. The Russian coals do not have the same level of quality control as other exporters but this situation should improve over time. Next promising is Indonesia, which passed Australia in 2004 as the largest global exporter of thermal coal. The Indonesian coal industry has expanded rapidly. The coal is not as high quality as that from other exporting countries, much of it is sub-bituminous. Indonesian coals have a range in sulfur contents from the ultra low sulfur of 0.1 % to over one %. The ultra low sulfur has gained some markets in the U.S. where its use has allowed utilities to comply with air pollution regulations without scrubbing. Penetration of Indonesian coals is limited due to the distance, combined with the lower heat content, which together increase transportation costs. Indonesian coals also generally require big vessels which not all importing terminals can accommodate. Other coals from Australia, South Africa, and elsewhere also present potential sources of imports.

Q. How are imported coals transported to FGPP?

A. Import coals are generally bought loaded into the vessel at the respective origin ports. Vessels would move the coal to an import terminal designated by FPL and the coal would then be offloaded at the terminal and put into rail cars for delivery to FGPP. FPL is evaluating access to both existing facilities and potential new import terminal locations in Florida.

Q. Given all of these considerations, is it likely that imported coal will be an economic source of fuel for FGPP?

A. Yes. Although world coal prices can fluctuate, the long-term trend is for world coal prices to fall relative to domestic coal prices, making imported coals a more likely supply to FGPP over time. FGPP is well-situated to receive imported coals, because of its location near the large supply region of South America. FPL's fuel supply plan has developed a sound strategy for delivering imported coals to FGPP economically and has provided flexibility to increase or decrease reliance on imported coal depending on the relative changes in the market compared to domestic coal over time.

PETROLEUM COKE

Q. What is petroleum coke?

A. Crude oil is turned into lighter transportation fuels in the refinery process. Refineries use a variety of methods to maximize production of the lighter transportation fuels including heating the heavy residual fuel oil in a coking process. Petroleum coke is a by-product of the coking process.

Petroleum coke has a high carbon content, low ash, and low volatility. If the petroleum coke has less than two % sulfur content and a low metals count, it can be calcined to produce anode coke, which is a higher value product used in the aluminum, steel and titanium oxide industries. Petroleum coke with more than two % sulfur is a fuel grade coke and historically has been a low valued, by-product material that was "disposed of" in the cement industry and, where possible, utility plants.

Q. How suitable is petroleum coke for pulverized coal boilers?

A. The low volatility of petroleum coke limits its use in pulverized coal boilers. Low volatility fuels burn slower than high volatility coal which creates issues with flame stability and carbon burnout. As a result, petroleum coke is typically limited to 20 % of the feed stock although some utilities have demonstrated success with slightly higher %ages.

Q. What is global petroleum coke production?

A. Global petroleum coke production capacity in 2005 is estimated to be 90 million tons; global 2005 production was about 85 million tons. 2005 production in the Gulf Coast and the Caribbean is estimated to be about 32 million tons.

Q. What is the outlook for petroleum coke supply?

A. Petroleum coke production is driven by crude oil and refined product prices. Ultimately, the supply of petroleum coke is a function of oil demand and crude oil quality.

Demand for crude oil continues to grow. Between 1990 and 2005, demand grew from 66 million barrels per day to 82 million barrels per day. Industry analysts including EVA forecast continued strong growth driven by China. EVA's forecast calls for an average annual growth of 1.6 % between 2005 and 2025 which results in a 2025 demand of 113.5 million barrels per day.

To satisfy demand growth, production increases are expected. As the incremental crude oil supply is expected to come from heavier and sourer crude oil, coking capacity is expected to be added and petroleum coke production will increase. Some forecasters expect annual petroleum coke production to exceed 120 million tons by 2010 and over 165 million tons by 2025.

Substantial coking capacity additions are underway at refineries in the Gulf and the Caribbean. Six projects currently under construction are listed in Document No. SS-17. Another eight or so are under development.

Collectively, these projects could add about 15 million tons of petroleum coke production within the next five to 10 years.

Q. What is the outlook for petroleum coke demand?

A. With its competitive pricing, demand for petroleum coke has been growing. While the industrial sector continues to be the primary market for petroleum coke, petroleum coke use in utility power plants has tripled since 1995. Nevertheless, total 2005 demand from domestic plants was less than eight million tons.

Because of its characteristics (i.e., high sulfur and low volatility), petroleum coke usage is limited in pulverized coal boilers, which account for most utility solid-fuel fired plants. Petroleum coke generally has a technical limit of about 20 %. Petroleum coke can be used for a larger share of fuel supply (in some cases up to 100 %) in fluidized bed combustors and integrated gasification combined cycle plants.

Several new fluidized bed projects are under development, which anticipate using petroleum coke as the primary source of supply. Existing projects include the repowering of two units at Jacksonville Electric Authority's (JEA) Northside plant for petroleum coke and projects adjacent to refineries such as the Entergy Nisco project at the Lake Charles refinery and the AES Deepwater project at the BP Houston refinery. Proposed new projects include CLECO's Rodemacher #3 plant in Louisiana, Edison's hydrogen project at the BP Carson refinery in California, and two new power plants in Texas.

Similarly, increased demand is expected from utilities for existing and new plants as part of the fuel mix. Growth from existing plants is expected as scrubbers are retrofit, thereby enabling the use of higher sulfur fuels. Growth from new plants is expected as utilities anticipate the use of petroleum coke as part of the blending stock. Examples of the latter include Santee Cooper at the new Cross units.

Q. How is petroleum coke priced?

A. The economics of petroleum coke in new or existing plants is tied to its price. Historically, petroleum coke prices have been very low (Document No. SS-18). However, as with other products, prices are set by the supply/demand balance although they have exhibited great volatility. Prices generally track the crude oil price, with ceilings set by coal prices. Prices soared to record levels in 2006 as a result of higher oil prices, residual supply related impacts from the active 2005 hurricane season, and predictions of an active 2006 season. Prices hit their ceiling in 2006, but have started to fall as at least two consumers (i.e., JEA and Nova Scotia Power) reported to have reduced petroleum coke purchases in favor of high sulfur coal.

Q. How is petroleum coke delivered to FGPP?

A. Petroleum coke is purchased either at the loading port or delivered to the terminal. If it is purchased at the port, the mechanics are the same as that for import coal. FPL charters the freight for delivery to the designated unloading terminal. If it is purchased delivered, the petroleum coke vendor charters its own freight for delivery to the designated terminal. In either event, FPL would be responsible for the rail from the terminal to FGPP.

PROCUREMENT STRATEGY FOR FGPP

Q. What is FPL's procurement strategy for FGPP?

A. As noted above, FPL's fuel plan is to source FGPP 40 % from Central Appalachia, 40 % imports, and 20 % petroleum coke. This procurement strategy incorporates the concept of a portfolio strategy through its supply and supplier diversification.

Q. What is a portfolio strategy?

A. Portfolio strategy is the leading practice with respect to fuel procurement. Adapted from a Nobel Prize winning theory on how investment profits can be maximized over time through diversified investments, in a portfolio strategy utilities purchase their fuel requirements under a combination of short, medium and long-term agreements with supply and supplier diversity. Furthermore, utilities seek to stagger expiration dates among the agreements in order to limit utility exposure to market at any one time.

Q. How will a portfolio strategy benefit FPL's customers?

A. This strategy is designed to provide a reliable fuel supply at stable prices over time. It will reduce the exposure to price volatility and will work to minimize long-term costs.

Q. Is FPL's fuel transportation strategy a sound and reasonable plan for FGPP?

A. Yes. The transportation strategy provides for multiple rail options to deliver coal to the FGPP site. This will provide competition among carriers and reduce transportation costs, as well as increase the reliability of service. The transportation strategy also provides access to coal terminals to import coal and petroleum coke by water for final delivery by rail. This increases FPL's options to purchase solid fuels from a wide variety of supply regions, allowing it to obtain the lowest-cost fuel over time.

Q. Will FPL have storage of coal and petroleum coke at FGPP and the terminal?

A. Yes. FPL will have up to 60 days storage of projected burn of coal and petroleum coke at FGPP and up to 30 days storage of projected burn of coal and petroleum coke at the terminal.

PRICE FORECASTS

Q. What are the delivered price forecasts assumed by FPL?

A. The delivered price forecasts assumed by FPL are provided in Document No. SS-19.

Q. How were the price forecasts developed?

A. FPL developed delivered price forecasts based upon assumptions regarding commodity prices, rail, ocean freight, and terminal charges. FPL also established a high and low case for the delivered prices based upon historic ranges in the delivered fuel prices to Jacksonville Electric Authority's St. Johns River Power Park, which is 20% owned by FPL and purchases a mix of solid fuels similar to the proposed supply to FGPP.

Q. Are the price forecasts reasonable?

A. Yes.

Q. How did you evaluate the reasonableness of the price forecast?

A. In February 2006, I prepared a delivered solid fuel price forecast for Orlando Public Utilities which was included in its Need for Power Application for the Stanton IGCC. I have compared the delivered price forecast for Central Appalachia, imports and petroleum coke to the Stanton site with FPL's delivered price forecast for FGPP. The FGPP site is reasonably close to the Stanton site and should have similar delivered solid fuel prices.

Q. What are the results of that comparison?

A. The results are provided in Document No. SS-20. My forecast for all three fuels in the Stanton testimony was within the range of FPL's forecasts for FGPP in this case.

Q. Please summarize your testimony.

A. FPL's plan to supply solid fuel for FGPP is a sound and reasonable plan, designed to achieve the lowest-cost mix of fuel (coal and petroleum coke) over the life of the project. The fuel transportation plan will provide economic options for delivery at reasonable prices with reliability of service. FPL's forecasted delivered prices for coal and petroleum coke are reasonable projections of future market prices. Finally, the addition of FGPP will provide increased diversity of fuel supply for power generation for FPL, which will reduce the volatility of electric power prices for FPL's customers.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF SETH SCHWARTZ

DOCKET NO. 070098-EI

MARCH 30, 2007

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

A. My name is Seth Schwartz. My business address is 1901 North Moore Street, Suite 1200, Arlington, Virginia 22209.

Q. **Did you previously submit direct testimony in this proceeding?**

A. Yes. I filed direct testimony on February 1, 2007. The purpose of my direct testimony was to provide background information on the coal industry and to provide EVA's expert opinion on an assessment of the transportation strategy FPL is employing at the FPL Glades Power Park ("FGPP") and to affirm the reasonableness of the projected delivered costs and procurement strategy for coal and petroleum coke included in this application.

Q. **What is the purpose of your rebuttal testimony?**

A. I was asked by FPL to review and comment upon the Direct Testimony and the Supplemental Direct Testimony filed by Richard C. Furman in the current proceeding.

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

A. Yes, I am sponsoring an exhibit consisting of 12 documents, Document Nos. SS-21 through SS-32, which is attached to my rebuttal testimony.

Q. Can you please summarize your findings?

A. Yes. Mr. Furman's testimony is that FPL should use Integrated Gasification Combined Cycle ("IGCC") technology for FGPP because it is allegedly lower in cost than the planned technology despite IGCC's higher capital costs. Mr. Furman's testimony hinges on his assumption of a substantial differential between the delivered price of petroleum coke and the delivered price of coal. Mr. Furman represents the prices used in his analysis were derived from historical data published by the Department of Energy. My basic conclusions are that Mr. Furman incorrectly applied historical data, failed to consider FPL's plan to burn a blend of coal and petroleum coke, and conducted no independent evaluation of the supply/demand balance for petroleum coke. As a result, Mr. Furman's finding that the cost of electricity generated from an IGCC plant would be lower than from FGPP is incorrect. Further, Mr. Furman incorrectly characterizes the current utility position with respect to IGCC plants.

FUEL COSTS USED BY MR. FURMAN

Q. What fuel costs did Mr. Furman assume?

A. The fuel costs assumed by Mr. Furman are shown in Exhibit RCF–5. They are $1.11 per MMBtu for petroleum coke and $2.38 per MMBtu for coal. Mr. Furman states that these fuel costs are based upon "Department of Energy, Energy Information Administration, <u>Average Delivered Cost of Coal and Petroleum Coke to Electric Utilities in Florida 2005 and 2004.</u>"

Q. Could you confirm the numbers used by Mr. Furman were in fact derived from the Energy Information Administration?

A. No. There is no document entitled "Average Delivered Cost of Coal and Petroleum Coke to Electric Utilities in Florida 2005 and 2004" as implied by Mr. Furman's underline.

Presumably, Mr. Furman used various tables from the Energy Information Administration's Cost and Quality of Fuels for Electric Utility Plants although he provided no specific table references or calculations.[1] The relevant Energy Information Administration tables for petroleum coke are attached to this testimony as Document Nos. SS-21 through SS-23. Document No. SS-21 is the average delivered cost of petroleum coke delivered to utilities by state in 2004 and 2005. Document Nos. SS-22 and SS-23 provide additional detail on the purchases for 2004 and 2005, respectively.

The relevant Energy Information Administration tables for coal are attached to this testimony as Document Nos. SS-24 through SS-26. Document No. SS-24 is the average delivered cost of coal by state in 2004 and 2005. Document Nos. SS-25 and SS-26 provide additional detail on the purchases for 2004 and 2005, respectively.

[1] http://www.eia.doe.gov/cneaf/electricity/cq/cq_sum.html

Document No. SS-27 compares the average delivered prices for petroleum coke and coal to Florida utilities as reported by the Energy Information Administration to the prices Mr. Furman represents in his testimony. Mr. Furman understates the delivered price of petroleum coke and overstates the delivered price of coal. More significant to this analysis, Mr. Furman overstates the spread between the two fuels by $0.36 per MMBtu.

Q. **Do the actual data published by the Energy Information Administration accurately reflect the average delivered prices of petroleum coke to Florida utilities?**

A. No. According to the Energy Information Administration, the price data reflect the data filed by the utilities on FERC Form 423. If the information filed by the utilities is inaccurate or not reflective of delivered costs, the published data will reflect these problems. A review of the actual FERC Form 423 filings shows that some petroleum coke shipments are to a terminal south of New Orleans on the Mississippi River, not to the power plant itself. As a result, the data do not show the full delivered price.

Q. **What petroleum coke shipments are only to New Orleans?**

A. Document No. SS-28 summarizes petroleum coke shipments to Florida utilities in 2004 and 2005 as reported by the utilities on FERC Form 423. The data are summarized by plant. As shown, Tampa Electric reports its petroleum coke purchases for Polk Power Station at its TECO Bulk Terminal, located in Davant, Louisiana. In other words, the prices reflect delivery only to Davant, not to Polk Power Station. Therefore, the reported costs do not include either the cost of transloading the petroleum coke from the terminal yard to the ocean-going barges, the cost of transporting it by barge across the Gulf of Mexico for delivery to TECO's Big Bend Station on Tampa Bay, the cost to unload the barges and transfer the petroleum coke to the storage yard, the cost to load the trucks, and the cost to transport the petroleum coke (whether by itself or blended with coal at Big Bend Station) 30 miles from Big Bend Station to Polk Power Station.

Q. Is this difference significant?

A. Yes. While it is hard to say what the exact difference is, there is no question it is material. An indication of the size of the difference can be seen by examining what Tampa Electric reported to the Florida Public Service Commission as Polk Power Station's fuel costs in 2005. Tampa Electric reports burn, heat rate, and fuel costs in dollars per megawatt-hour for each unit on a monthly basis. As shown in Document No. SS-29, in 2005 Polk Power Station burned 490,000 tons with an average fuel cost of $2.19 per MMBtu. Polk Power Station burns a blend of petroleum coke and coal. The additional costs from Davant include the transloading fee, the Gulf barge fee, the unloading fee at Big Bend, and the trucking charge from Big Bend Station to Polk Power Station. Together, these are significant costs that are not included in Mr. Furman's testimony or exhibits.

Q. Are there other reasons why the Energy Information Administration data would not be a reliable measure of the delivered price for petroleum coke to FGPP?

A. Yes. FGPP is not a coastal plant. As such, the petroleum coke will be delivered to an import terminal, transloaded and then railed to the plant.

Therefore, the price of petroleum coke delivered to a coastal utility will not reflect the delivered price to FGPP. All of the petroleum coke purchased by Jacksonville Electric Authority is delivered directly to St. Johns River Park and Northside and are not comparable to FGPP. Collectively, these deliveries account for over 50 percent of the petroleum coke purchased by Florida utilities in 2004 and 2005. The reported delivered price to inland utilities like the City of Lakeland is about $0.50 per mmBtu higher than the price to the coastal utilities, reflecting the increased transportation costs.

Q. **Mr. Furman supplies an average of the 2004 and 2005 data in his testimony. Do you agree with his methodology?**

A. As discussed above, his data were not correct or do not represent the market for FGPP. Even if the data were correct and comparable, Mr. Furman's methodology of using historical data to estimate future prices is not appropriate for this purpose. The presumed intent of Mr. Furman's exercise was to determine whether the electricity generated by an IGCC plant would be more economical than by the proposed FGPP. As such, the relevant numbers are the projected costs, not historical ones. There is no indication that Mr. Furman considered any forecast of petroleum coke or coal prices. Mr. Furman confirmed in his deposition (pages 10-11) that he only looked at historical fuel cost information for 2004 and 2005, and did not prepare or rely upon any projections of future fuel prices.

This omission is particularly striking in the context of the 2004 and 2005 data. Between 2004 and 2005, according to the Energy Information Administration data on delivered prices of petroleum coke to Florida utilities, the average cost increased by almost 50 percent. At a minimum, this increase should have raised questions as to the cause of the increase and whether this step increase was likely to continue into the future.

FPL FUELING PLAN FOR FGPP

Q. What is FPL's fueling plan for FGPP?

A. The baseline fuel plan for FGPP is a blend of domestic coal (40 percent), imported coal (40 percent), and petroleum coke (20 percent). FPL intends to adjust the percentages based upon the relative economics whenever fuels are purchased subject to technical limitations.

Q. Did Mr. Furman acknowledge FPL's fueling plan for FGPP?

A. No. Mr. Furman made no mention of FPL's fueling plan presumably as it would have required him to adjust the fuel cost assumptions in Exhibit RCF-5 for the non-IGCC case to reflect a blend with 20 percent petroleum coke. This would have had the effect of reducing the fuel cost savings which he projects for the IGCC plant, making it less economic. In his deposition (page 11), Mr. Furman admitted that he did not consider South American coal at all, even though it is part of FPL's fuel plan. In fact, Mr. Furman admitted that he did not even prepare Exhibit RCF-5 (which contains his economic analysis, including fuel costs) for use in this proceeding.

Q. Did Mr. Furman suggest that FGPP will have lower availability than an IGCC project because of a potential interruption in its coal supply?

A. Yes. On page 13, lines 20-22 of his Supplemental Testimony, Mr. Furman alleges that "a coal supply interruption, such as a coal strike, can cause the loss of all 1,960 MW because no backup fuel is available." There has not been a coal strike in the United States since 1993, and that strike did not cause any coal-fired plants to run out of coal and shut down. Further, only 21 percent of U.S. coal production came from union mines in 2005, and the union share of production has been declining steadily. Plants like FGPP maintain a stockpile of coal on site to address any disruptions in coal supplies, and this strategy has been quite successful in avoiding the shut down of any coal-fired capacity due to lack of coal supply.

PETROLEUM COKE MARKET OUTLOOK

Q. In your direct testimony, you provided background information on the petroleum coke market as well as your outlook for petroleum coke supply. Did Mr. Furman or any other party comment on your direct testimony in his testimony?

A. No. Moreover, Mr. Furman admitted in his deposition (pages 60-61) that he is not an expert in projecting petroleum coke prices, and he has not performed any projections of petroleum coke prices or availability.

Q. In your testimony, did you explain that the petroleum coke market had changed in recent years?

A. Yes. I explained that petroleum coke production had increased and that continued global increases in the demand for oil and increased use of heavier crude oils would result in continued increases in production of petroleum coke. Document No. SS-30 provides a review of U.S. petroleum coke production during the period 1995 through 2005. Over this period, production increased by 46 percent while exports only increased by 25 percent. There was significant growth in domestic consumption of petroleum coke by both utility plants and industrials.

Q. Did you explain that domestic demand for petroleum coke is expected to increase as a result of the massive retrofitting of scrubbers that is currently underway in the U.S. in order to comply with the Clean Air Interstate Rule ("CAIR") and various state regulations and consent agreements?

A. Yes. I explained that the retrofits of flue gas desulfurization (FGD) equipment on existing power plants would allow utilities to incorporate petroleum coke into their fuel mixes. I did not provide the magnitude of the increase. As shown in Document No. SS-21, EVA expects over 80 gigawatts ("GW") of FGD retrofits of eastern U.S. generating capacity. Assuming up to 20 percent blend of petroleum coke in a pulverized coal boiler, these retrofits could increase U.S. utility demand for petroleum coke by over 30 million tons.

Q. Did you also explain that petroleum coke demand would increase as a result of the construction of new fluidized bed combustors, IGCC plants and PC plants?

A. Yes. I noted that several new fluidized bed projects are under development and anticipate using petroleum coke as the primary source of supply, including projects adjacent to refineries similar to the existing Entergy Nisco project at the Lake Charles refinery and the AES Deepwater project at the BP Houston refinery. I noted but did not list that there are also several new utility plants in construction or under development that plan to use petroleum coke as their primary fuel. These plants are listed in Document No. SS-32. Finally, I noted but did not list the fact that a number of new utility plants are planning to use fuel blends that include petroleum coke. In Florida alone, the Stanton IGCC (Orlando), the Taylor Energy Center (JEA et al), and the new Seminole Generating Station Unit #3 all plan to use a fuel blend that includes petroleum coke.

Q. In your direct testimony, did you explain that petroleum coke prices are not cost driven but set by the supply/demand for petroleum coke?

A. Yes. I explained that the petroleum coke generally tracks petroleum prices subject to supply and demand. If demand increases as a result of the FGD retrofits, new Fluidized Bed Combustion ("FBC") plants, new IGCC plants and new PC plants, the price for petroleum coke will balance at the avoided coal price for the marginal plants, and there will be no fuel cost savings from using petroleum coke, as relied upon by Mr. Furman to justify the higher capital cost of the IGCC plant.

Q. Did you explain that petroleum coke prices are capped by the price of coal because utilities can switch to coal if prices rise to that level and that in 2006 some utilities reduced petroleum coke purchases as a result of high prices?

A. Yes. I explained in 2006 that several utilities reduced petroleum coke consumption in favor of coal as a result of high petroleum coke prices.

Q. Based upon Mr. Furman's testimony, do you believe he understands the market for petroleum coke?

A. No. There are several indications that Mr. Furman does not understand the market for petroleum coke.

On page 9, lines 13-17, Mr. Furman states of the 25 million tons of fuel grade petroleum coke produced in the Gulf, "**almost all** of this petcoke is exported to other countries that allow the higher emissions of SO_2 that petcoke produces." (emphasis added) As discussed above, significant and growing quantities of petroleum coke produced in the Gulf are consumed domestically. In fact, about 8 million tons per year is consumed domestically, and only 17 million tons per year are exported.

Mr. Furman states on page 9, lines 18-19 that "[t]he use of petcoke in the U.S. requires the installation of additional FGD systems to PC plants which is usually cost prohibitive." As stated above, over 80 gigawatts of eastern coal capacity are expected to be retrofit with FGD systems, suggesting it is hardly cost prohibitive.

Mr. Furman states on page 9, lines 21-23, that **"Florida's proximity to the Gulf coast refineries** enables Florida's utilities to make use of **this waste material** while reducing emissions and lowering their cost of electricity." (emphasis added) As previously discussed, the coastal plants in Florida that can receive coal by vessel may be proximate to the Gulf coast refineries, but FGPP is not located on the coast. Because FPL does not have a coastal plant site on which an IGCC could be located, any IGCC plant would also be located at an inland location. Such an inland location would require that the petroleum coke from the Gulf be taken to an import terminal, transloaded into rail cars and railed to the power plant. All of these costs must be considered in any evaluation.

Further, Mr. Furman's characterization of petroleum coke as a waste product is inappropriate. Petroleum coke may be a by-product of refinery but it is hardly a waste product. If it were a waste product, the refineries would either give it away or pay consumers to "take it off their hands" to avoid disposal costs. Petroleum coke is currently selling at over $40 per ton free on board ("FOB") vessel on the Gulf Coast. This is not the pricing of a "waste product".

Finally, Mr. Furman does not quantify the petroleum coke requirements for his suggested strategy. As a petroleum coke-only supplied IGCC, FGPP would require in excess of four million tons of petroleum coke per year. This additional demand alone would equal 25 percent of the total annual exports of petroleum coke, which would affect the market and pricing for petroleum coke.

Q. **Would a fuel strategy which relies exclusively on over four million tons per year of petroleum coke be a prudent fuel supply decision?**

A. No. The demand for a plant the size of FGPP would equal over 15 percent of the total supply of petroleum coke. This would leave FGPP far too dependent upon a very limited source of fuel, and would not be as reliable as relying upon a blend of coals from multiple supply regions, in addition to petroleum coke.

INDUSTRY COMMITMENT TO IGCC

Q. **Did Mr. Furman misrepresent the success of IGCC in the U.S.?**

A. Yes. On page 17, Mr. Furman is asked how long commercial size IGCC plants have been in operation in the U.S. Mr. Furman responds "Commercial IGCC plants have been in operation for more than 10 years in the U.S." He then goes on to describe the Polk and Wabash plants. Mr. Furman does not explain that three IGCC projects (Polk, Wabash, and a third plant Pinon Pine) were built with co-funding from the Department of Energy and that Pinon Pine was a failure and never operated. Mr. Furman also does not mention that Wabash was idled in 2004 and was not returned to service for over a year until it was sold to a third party. In other words, there has been no IGCC plant built and operated in the U.S. to date on a totally commercial basis and performance has been less than reliable.

Q. Did Mr. Furman misrepresent industry commitment to IGCC?

A. Yes. On page 18 of his direct testimony, Mr. Furman states that "there are least twenty-eight (28) IGCC plants being planned in the United States by utilities and independent power producers." A partial list is provided in Exhibit RCF-17. On page eight of his supplemental testimony, Mr. Furman now states there are 32 IGCC plants under development and he cites a NETL report. (http://www.netl.doe.gov/coal/refshelf/ncp.pdf) Mr. Furman does not cite NETL's own qualifying statements which state "[p]roposals to build new power plants are often speculative and typically operate on "boom & bust" cycles, based upon the ever changing economic climate of power generation markets. As such, **it should be noted that many of the proposed plants will not likely be built.**" (emphasis added) Mr. Furman also fails to mention that one of the 32 proposed IGCC plants he references is an FPL IGCC plant under study for St. Lucie County. This plant is not presently planned by FPL.

Q. In what other way does Mr. Furman misrepresent IGCC as the favored technology?

A. Mr. Furman does not provide a balanced outlook with respect to new coal generating capacity. For example, Mr. Furman speaks to American Electric Power's commitment to IGCC in Ohio and West Virginia but does not mention American Electric Power's commitment to an ultra-supercritical plant in Arkansas and possibly Oklahoma. Similarly, Duke Energy is proceeding with the development of new supercritical pulverized coal plant in North Carolina at the same time it is pursing the development of an IGCC in Indiana.

Another example is Mr. Furman's Exhibit RCF-10, where he lists emission limits for three permitted IGCC plants and fails to mention that none of these have been built. We Energies is building Elm Road as a supercritical pulverized coal plant. Kentucky Pioneer has been cancelled with the withdrawal of Department of Energy support. Global Energy's Lima plant is only notionally under construction as it has no financing or off-take agreements.

Q. Does this conclude your testimony?

A. Yes.

BY MS. SMITH:

Q. Mr. Schwartz, have you prepared a summary of your direct testimony?

A. Yes, I have.

Q. Would you please provide that summary to the Commission?

A. Yes. I was engaged by FPL to provide an expert opinion on FPL's transportation and fuel supply strategy and the reasonableness of the projected delivered fuel costs for FPL's Glades Power Park.

Like other utilities in Florida, FPL's reliance on coal-based generation is less than the national average. In 2005, FPL's ownership interest in Scherer Number 4 and St. Johns River Power Park contributed only 5.2 percent to FPL's power sales.

Historically, coal prices have displayed lower volatility than natural gas or oil prices. The commitment to FGPP will reduce FPL's fuel prices and reduce price volatility for FPL's customers.

FPL's baseline fuel plan for FGPP calls for a blend of 40 percent Central Appalachia coal, 40 percent imported coke, and up to 20 percent -- imported coal, I'm sorry, and up to 20 percent petroleum coke. These shares can be adjusted to take advantage of the lowest cost fuel at the time. This plan is reasonable, as it will provide sourcing flexibility and allow FPL to realize a low fuel cost with reliable supplies.

I would like to provide a brief overview of FPL's proposed fuel supplies. Central Appalachia is the second largest coal supply region in the United States and is the closest coal supply region to Florida. FPL's forecast of coal supply and prices from this region has taken into account the impacts of the long-running dispute over surface mining, which was the subject of a recent West Virginia court decision. Two class 1 railroads provide service between Central Appalachia and Florida, and FPL's transportation strategy provides for the use of both railroads in order to retain competition.

Imported coals would likely originate in South America, although other sources are possible as well. Both Colombia and Venezuela export large volumes of high quality steam coal.

Petroleum coke is a refinery by-product, which can be a lower cost fuel, and many utilities have successfully incorporated it into their fuel supply program. The petroleum coke most likely to supply FGPP would originate from refineries in the Gulf of Mexico or the Carribean. The imported coal and petroleum coke would move through existing or new import terminals.

Other plants in Florida have successfully employed a similar fuel supply strategy. Throughout its operations, St. Johns River Power Park has relied on a similar blend of South American and Central Appalachia coals as well as petroleum coke. Other plants in Florida rely on petroleum coke for a portion of their fuel supply, including Big Bend, Seminole, Lakeland, and JEA's Northside plant.

My key findings are as follows:

Number one, FGPP will help FPL diversify its generation portfolio and will reduce fuel prices and fuel price volatility.

Number two, FPL has developed a fuel supply plan that is not dependent upon a single coal supply region or fuel type. The ability to use coal from more than one supply region provides both security of supply as well as market competition. This security of supply and competition is further enhanced by FGPP's access to two class 1 railroads. The incorporation of petroleum coke into the FGPP plant design allows for an economic source of fuel when the opportunity is presented.

Third, the delivered coal price forecast developed by FPL is reasonable and is consistent with a forecast which I prepared and submitted to this Commission in February of 2006 on behalf of the Orlando

Public Utility Commission as part of its need for power application on the Stanton coal project.

Thank you very much.

Q. Mr. Schwartz, have you also prepared a summary of your rebuttal testimony?

A. Yes, I have.

Q. Would you please provide that summary to the Commission.

A. Yes. My rebuttal testimony responds to the assertion of Mr. Richard Furman that an IGCC would be a lower cost option for FPL's customers despite its higher capital costs, because an IGCC would be fueled by petroleum coke, and that the cost differential between coal and petroleum coke would more than offset the higher capital costs.

I conclude that Mr. Furman's findings are incorrect because his fuel cost assumptions overstate the differential between the delivered price of coal and petroleum coke. Mr. Furman assumes that petroleum coke will cost less than half the price of coal based on the average 2004 and 2005 delivered coal prices reported -- to Florida power plants reported by the Energy Information Administration. I've reviewed the relevant Energy Information Administration reports and found that Mr. Furman's numbers are wrong and that the reported petroleum coke costs do not represent fully delivered costs to Florida's power plants.

Further, the average petroleum coke cost to Florida Power plants do not reflect fuel economics at FGPP, because FGPP is an inland plant and has different delivery characteristics than a coastal plant, where most petroleum coke is used.

Mr. Furman's conclusions were also based upon a comparison between an IGCC using 100 percent petroleum coke to an ultra-supercritical boiler using 100 percent coal. FPL indicated in its application that its fuel plan for FGPP would use 80 percent coal and 20 percent petroleum coke. Mr. Furman has overstated the fuel cost differential by not including a petroleum coke component in his assumed fuel costs for the ultra-supercritical option.

Mr. Furman also failed to consider that the market for petroleum coke would change if petroleum coke were widely used as a fuel strategy for many new power plants, as suggested by Mr. Furman. The petroleum coke market is very small compared to the coal market, and one new plant the size of FGPP would consume over one-fourth of the current uncommitted domestic supply of petroleum coke if it used exclusively petroleum coke.

The price for petroleum coke is affected by petroleum prices, as well as by supply and demand, but is capped by the price of alternative fuel, which is coal. If there is a large increase in demand for petroleum coke as expected by Mr. Furman, the price for petroleum coke would rise to the avoided coal price, eliminating the price differential Mr. Furman requires to justify an IGCC project.

Mr. Furman has also misrepresented the success of IGCC projects in the United states. There is not a single IGCC project which has been built without large government subsidies. Only four small IGCC projects have been built in the United States, of which two were closed shortly after startup, and one was idled for an extended period of time. Despite the fact that there have been many proposed new IGCC projects, not a single one is under construction, and many of the proposed plants have been abandoned.

In conclusion, Mr. Furman failed to consider FPL's fuel strategy for FGPP, conducted no evaluation of petroleum coke supply and demand. Reliance on 100 percent petroleum coke for a project the size of FGPP would not be a prudent fuel supply strategy, and the widespread development of coke-fired IGCC projects would cause petroleum coke prices to rise to equal the price of coal.

Thank you very much.

MS. SMITH: Madam Chairman, Mr. Schwartz is available for cross-examination.

CHAIRMAN EDGAR: Thank you. Ms. Perdue. No questions.

Mr. Beck.

Mr. Gross.

MR. GROSS: Madam Chair, Sierra Club, et al., and NRDC, we do have questions. Thank you.

CROSS-EXAMINATION

BY MR. GROSS:

Q. Good afternoon, Mr. Schwartz.

A. Good afternoon.

Q. I'm Michael Gross, and I represent Sierra Club and NRDC and several other environmental organizations. I've got some questions for you.

Referring to page 5, lines 18 through 22 of your direct testimony, you state, "Petroleum coke supply is expected to expand over time as additional coking capacity is installed. Petroleum coke is a lower cost source of Btu's that many utilities have successfully incorporated into fuel supply as a means of controlling costs. The low volatile content of petroleum coke limits the extent to which it can be burned as part of a fuel blend." And then refer to page -- and this is leading up to a question. Page 8, lines 9 through 10, where you state, "FPL's fuel supply plan is to burn a blend of coals consisting of 40 percent Central Appalachia coal, 40 percent imported coal, and 20 percent petroleum coke." Is that correct?

A. Yes. It's up to 20 percent petroleum coke in the fuel supply plan.

Q. Okay. It could be less than 20 percent?

A. It could be less than 20 percent if the economics are not favorable.

Q. Twenty percent petcoke, as it's also referred to, 20 percent petcoke is the maximum amount of petcoke that can be used in FPL's USCPC plant design; is that correct?

A. That's correct.

Q. And this use of petcoke will generate fuel cost savings; correct?

A. Under the base case projections, it's expected to be lower cost than coal. But petcoke prices have been very volatile, in part because of volatility of oil prices, and sometimes it's less expensive, and sometimes it's not.

Q. Well, at page 9, lines 23 through 24, you state, "FPL has incorporated petroleum coke into its plant design, permit, and fuel supply plan. Petroleum coke is an economic source of energy that has provided a number of utilities with an effective means of minimizing fuel costs."

A. Is that a question?

Q. Is that what you stated in your testimony?

A. Yes, that's what I stated in my testimony. Over a long period of time, petroleum coke has been typically less expensive than coal, but it's not always. Unfortunately, in the current market we're experiencing right now, petroleum coke prices have risen to equal or above the price of coal, and as a result, Jacksonville Electric Authority and Seminole Electric are not going to purchase petroleum coke this year. That flexibility to shift from one supply to the other and use the most economic source of fuel is part of the strength of the fuel strategy for FPL's Glades Power Park.

Q. Well, you filed your testimony on January 29, 2007. Has all this change occurred since you filed your testimony?

A. No. Prices -- I have a chart in here -- if you'll look, it's one of my exhibits -- showing historical prices for petroleum coke. Petroleum coke prices, as you can see from there, are highly volatile, in part because of the price of oil, which is the source of it. I have a chart on Exhibit SS-18.

No, the price has already increased substantially by early 2006, and as a result, some utilities like these in Florida are reducing their use of petcoke at the present time.

Q. Thank you. On page 29, lines 13 through 15, you stated, "Because of its characteristics, that is, high sulfur and low volatility, petroleum coke usage is limited in pulverized coal boilers, which account for most utility solid-fuel fired plants." Do you still stand by that statement?

A. Yes.

Q. And, "Petroleum coke generally has a technical limit of about 20 percent." Do you stand by that statement?

A. Yes. That's referring to pulverized coal fired plants.

Q. Petroleum coke can be used for a larger share of fuel supply, in some cases up to 100 percent, in fluidized bed combustors and integrated gasification combined cycle plants, commonly known as IGCC plants; correct?

A. That's correct, yes.

Q. Okay. The use of 100 percent petcoke in an IGCC plant will provide five times the fuel savings of the proposed 20 percent petcoke in the Glades Power plant; correct?

A. No, I wouldn't agree with that. Again, there's a lot of factors that go into selecting and delivering the lowest cost fuel. Having a flexible fuel supply strategy like FGPP I think is one way utilities have used to minimize fuel costs over a long period of time. Petroleum coke is typically less expensive than coal, but not all the time, and not right now.

Q. Ratepayers would benefit from fuel cost savings, would they not?

A. Obviously, it's a long-term levelized cost analysis that includes capital and operating costs as well as fuel costs. If that's taken into account, yes, lower fuel costs are generally beneficial.

Q. At page 10, lines 9 through 11 of your direct testimony, you state, "There are five major commercial producing coal areas in the U.S., of which the largest is the Powder River Basin." Is that correct?

A. Yes, it is.

Q. And in Exhibit SS-4 of your testimony, you present a table that shows that Powder River coal represents 38 percent of total U.S. production; is that correct?

A. I haven't calculated the percentage on that table, but that looks approximately correct, yes.

Q. Powder River Basin coal is the lowest cost coal as shown in your Exhibit SS-8?

A. It's certainly the lowest cost coal at the mine. Obviously, it's located in a remote area, and as a result, depending upon where the power plants are located, the transportation costs can be extremely high, frequently many times the price of coal at the mine. But it is the lowest cost coal to mine, but not necessarily the lowest cost delivered.

Q. Well, Exhibit SS-8 shows Powder River Basin coals at the mine cost about $7 per ton versus 40 to $60 per ton for other coals; is that correct?

A. No, that's not exactly correct. Powder River Basin coal is a little less than $10 per ton. The other U.S. coals at the present time are running prices in the range of 40 to $45 per ton. The $60 price you're looking at is a delivered price of international coal to Europe, which is not the same thing as mine prices in the United States.

Q. Well, the proposed Glades plant cannot use Powder River Basin coal; is that correct?

A. I don't know for sure technically. I know it's not part of the fuel supply plan; that's correct. The Glades plant is a long way from Wyoming, and just because Powder River Basin coal is the lowest cost coal at the mine doesn't make it the lowest cost coal delivered to Florida, and it's the delivered price economics that are what are important.

Q. Looking back at your Exhibit SS-4, you present a table that shows that the other Western coals represent 19 percent of total U.S. production. Is this correct?

A. That looks approximately correct, yes.

Q. And the proposed Glades plant cannot use most of these other Western coals; correct?

A. I don't think that's correct, no. I think the Glades plant could use the bituminous coal from the Rockies, which is the largest other region. It's not part of the current fuel supply plan because it is grossly uneconomic compared to the coals that have been selected for the Glades plant. But if for some reason those coals were all of a sudden to become much less expensive because rail rates from Colorado fell dramatically, FGPP could adjust its fuel supply plan and use that coal.

Q. On page 9 of your direct testimony, lines 12 through 14, you state, "Although Illinois Basin coal is used by some of the coal-fired plants in Florida, this coal tends to be high in chlorine and is not compatible with the plant and scrubber design selected for FGPP";

correct?

A. Yes. My understanding is on technical limitations, coals over a certain chlorine level are excluded from the fuel choices for FGPP.

Q. Therefore, Illinois Basin coal, which represents 8 percent of total U.S. production, is also not able to be used in the proposed Glades plant; is that correct?

A. No, that wouldn't be true for all of Illinois Basin coal. That would be true for the higher chlorine content coals, which are typically found in the central part of Illinois.

Q. Therefore, the domestic coal supply that FPL has focused specifically on is the Central Applachian coals, which according to your Exhibit SS-4 represents only 21 percent of total U.S. production; is that correct?

A. Which part of your question? No, I wouldn't say that they focused only on Central Appalachia coal. Yes, I would say that it does represent a little over 20 percent of total U.S. coal supply and is the largest coal supply region in the East.

Q. At page 8, lines 12 through 13 of your direct testimony -- excuse me. I want to make sure. Did I say on page 18?

A. No, you did not.

Q. Okay. I meant page 18, lines 12 through 13. You stated, "EVA's most recent long-term forecast, which is provided in Document No. SS-11," which is an exhibit to your testimony, "calls for Central Appalachia coal demand to decline from 235.6 million tons in 2005 to about 173 million tons in 2020." Is this correct?

A. Yes, it is.

Q. Now, in answer to a question on page 17, lines 4 through 20, you were asked the question, "Please provide an overview of the Central Appalachia coal supply region." And I'm going to paraphrase just to make more efficient use of time, but basically you said that Central Appalachia includes coal production from eastern Kentucky, southern West Virginia, and you listed a few other states in that area, and is the largest coal supply region in the eastern U.S., although production has declined since 1990, as shown in your Exhibit SS-9; is that correct?

A. Yes.

Q. And you mention that the remaining reserve blocks in Central Appalachia are smaller and less conducive to either large surface mining operations or large underground mining operations; correct?

A. Less than other supply regions, such as the

Powder River Basin, where the surface mines are huge, or the underground mines, so-called long wall mines in Northern Appalachia and the Illinois Basin. Central Appalachia tends to consist of smaller reserve blocks and many smaller operations and uses different mining techniques as a result.

Q. You mention that the mines are generally small, less than 2 million tons per year, and have limited lives such that each mine typically has typically less than 10 years of production; correct?

A. That's correct, yes.

Q. And as a result, there's a continuous need for new mine development and reserve acquisition in Central Appalachia; correct?

A. Yes.

Q. Okay. And since this area is not conducive to either large surface mining or underground mining, there must be more mountaintop coal mining in these states associated with -- with its associated environmental damage. Is this correct?

A. No. Underground mining still is the primary mining technique. I'm not saying there isn't underground mining in Central Appalachia. I'm just saying you don't have the type of large reserve blocks that are conducive to the same type of mining as you see in the Illinois Basin. And there's a lot of surface mining in Central Appalachia, not all of which is mountaintop removal mining. Some of it is, and some of it is not. But all of it -- we've had a long history of coal mining in Central Appalachia going back 100 years, and it uses both surface and underground mining.

Q. Based on your testimony, Mr. Schwartz, regarding Central Appalachia coal, FPL is not going to achieve fuel diversity, because it is depending upon a depleting production area that will create significant environmental damage; is that correct?

A. No, that's not true at all. The demand for coal from this region is declining, not the supply. The reason why the demand is declining is that many utilities required the use of this low-sulfur coal due to the Clean Air Act, because they switched to low-sulfur coal instead of building scrubbers.

Now many of those utilities are building scrubbers in response to the Clean Air Interstate rule, and as a result, they're switching back to using their closest coal supplies, which for utilities in Indiana, Ohio, Pennsylvania, and Illinois is not Central Appalachia. As a result, demand is falling, which means the supply is adequate to be supplying its natural market, which is the southeast United States, including plants in Florida. That's why that coal is expected to be a low cost coal for a plant located in Florida.

Q. Isn't it true that the FGPP plant design cannot make use of most of the coals available in the U.S.?

A. That's not true at all. They can use -- FGPP could use any of the coals in Appalachia, including Northern Appalachia and Southern Appalachia, as well as Central Appalachia. It's just not under current projections expected to be the lowest cost supply. FGPP can also use any of the bituminous coals in the western United States, but again, it's not expected to be lower cost compared to the least cost fuels, which would be from Central Appalachia or imported coal with a blend of petroleum coke.

FGPP is limited in its ability to use Illinois Basin coal to the extent the coals are higher chlorine, but there are lower chlorine coals in the Illinois Basin that could be part of the fuel supply mix. But again, Illinois is a lot farther away than eastern Kentucky is, so it's not expected under our projections that that would be the most economic source.

Q. And FGPP, as you stated earlier, can only use a maximum of 20 percent petcoke; correct?

A. That's correct. That's my understanding.

Q. IGCC plants, on the other hand, can use 100 percent petcoke; is that correct?

A. If designed for it, yes. Plants like the Polk plant are limited and I think are blending approximately 60 to 70 percent petroleum coke, with the rest being imported coal.

Q. It's true, is it not, that IGCC plants can make use of more U.S. supplies of coal than the proposed FGPP plant?

A. No, I wouldn't say that's true. It all depends how you design the plant. FGPP is being designed for the least cost fuel. It could use other fuels as well. And an IGCC will have to be designed for a fuel also. Any plant can be designed for anything, but once designed, its limitations are based upon what its design is.

Q. Well, IGCC plants can make use of more foreign coals than the proposed FGPP plant; correct?

A. I don't think that's true at all. I think FGPP could use any foreign coal available in the market today.

Q. IGCC plants can be operated on natural gas and distillate oils; is that correct?

A. That I don't know. I suppose it's possible. I really haven't looked.

Q. IGCC plants can be fueled by biomass and waste materials; correct?

A. No. Again, you can design any plant to do anything, but you could put biomass and waste in FGPP also. But I don't think there's any real prospect that an IGCC plant is being built for biomass, certainly not anywhere in this country.

Q. IGCC plants provide more fuel flexibility and many more opportunities for fuel cost savings than the proposed Glades plant; correct?

A. I wouldn't agree with that, no.

Q. Your Exhibit SS-18 shows Gulf Coast petcoke prices from 2002 to 2006 ranging from $7 a ton to $42 a ton and averaging about $17 a ton; correct?

A. I haven't prepared an average, but, yes, it's correct that it ranges from 7 to about $42 per ton.

Q. And this chart also shows the significant variability in petcoke prices; correct?

A. Yes, it does.

Q. What is important is the long-term average fuel cost differential, is it not?

A. I'm not sure I understand your question.

Q. In terms of fuel cost savings, the long-term average fuel cost differential is what's most important?

A. Differential between what and what? I'm still not sure I understand your question.

Q. Excuse me just one second.

The differential between petcoke and coal.

A. That's certainly one thing they're considering at FGPP, but I think probably more important is the long-term differential between solid fuel and natural gas. That's where I thought maybe you were headed. I'm not sure what you mean about coal and petcoke, the differential being important. Certainly that's part of what's taken into account in the design and purchasing decisions.

Q. Referring to Exhibit SS-19, titled "FPL Medium Case Forecast of Delivered Coal Prices," that exhibit shows the projected fuel cost savings between coal and petcoke, does it not?

A. Not savings, no. It shows the medium case projected delivered prices in dollars per million Btu, including the two sources of coal and petroleum coke that are the most likely supply for FGPP.

Q. Well, this FPL forecast shows that the fuel cost savings between coal and petcoke increases from about $1 per million Btu's in 2013 when the FGPP starts operating to $1.60 per million Btu's in 2024; is that correct?

A. I'm not sure I can read with precision 2024, but, yes, it does -- it does show the price of coal being about 50 percent higher than the price of petroleum coke on a delivered price base, and that differential stays constant in percentage terms roughly through the life of the forecast. It's growing because of the effect of inflation over time.

Q. This demonstrates by FPL's own estimates the increase in fuel savings that can be provided by a plant that can use multiple fuels, including 100 percent petcoke; correct?

A. No, I don't think that's what it demonstrates. It is the base case -- you know, the medium case forecast of delivered prices of the different fuels, and the plant has been designed to take that into account.

Q. At page 12, lines 22 through 23 of your rebuttal testimony, you state, "As a petroleum coke-only supplied IGCC, FGPP would require in excess of 4 million tons of petroleum coke per year." Is this correct?

A. Yes, it is.

Q. On page line 28, lines -- excuse me. On page 28, lines 14 through 19 --

MS. SMITH: I'm sorry. Is this of --

BY MR. GROSS:

Q. This is of your direct. I'm jumping back and forth a little. You were asked the question, "what is the outlook for petroleum coke supply?" And your response included the following statement: "To satisfy demand growth, production increases are expected. As the incremental crude oil supply is expected to come from heavier and sourer crude oil, coking capacity is expected to be added and petroleum coke production will increase. Some forecasters expect annual petroleum coke production to exceed 120 million tons by 2010 and over 165 million tons by 2025." Is this correct?

A. Yes. That's the entire world petroleum coke supply, taking into account, you know, all of Europe, Asia, et cetera.

Q. Therefore, the 4 million tons per year needed by FGPP would only represent 3 percent of total petcoke production in 2010 and 2 percent of total production in 2025, based on world production?

A. Of total world production, yes. But that's not necessarily accessible to the U.S. markets and obviously has other demand for that product as well. I mean, to put that in context, compared to coal, world coal production is 5 billion tons per year, of which FGPP then would be .1 percent, not 4 percent. It's a pretty big difference, especially if you're looking at what's available here in the U.S. As you can see from the price volatility, petroleum coke markets are what we would call a thin market. It's not that large in supply and demand, and so therefore, large swings can make a big impact on prices.

Q. I just have a few questions, and I'm about to wrap up. On page 27, line 24, you state -- of your direct testimony -- let me make sure. Global 2005 production was about 85 million tons; is that correct?

A. That's correct.

Q. And Exhibit SS-30 to your direct testimony --

MS. SMITH: Actually, I think that may be rebuttal.

BY MR. GROSS:

Q. Excuse me. That's on your rebuttal testimony. Have you found that?

A. Yes.

Q. Okay. It shows that U.S. 2005 marketable production was about 43 million tons; correct?

A. That's correct.

Q. And Exhibit SS-30 shows that Gulf Coast 2005 marketable production was about 24 million tons; correct?

A. Yes, it was.

Q. Therefore, the Gulf Coast production of petcoke represents more than half of U.S. production; is that correct?

A. Yes. Many of the U.S. refineries are located in the Gulf Coast.

Q. And U.S. production represents more than half of the world's production of petcoke; correct?

A. Yes, it does, or approximately half. I wouldn't say more than half. It's right about half.

Q. So it appears that Florida has a unique opportunity to use this low cost fuel in a method, IGCC plants, that will significantly reduce the present environmental emissions created by the export of petcoke; correct?

A. No, I wouldn't say Florida has some unique opportunity to use this fuel. Yes, the larger share of U.S. petcoke production is in the Gulf Coast. There's also a lot of demand for it. And as you can see, the available exports of petcoke today are 16 million tons per year. Nobody is going out and building a 2,000-megawatt plant to use petroleum coke like the size of FGPP just depending on market supplies for petroleum coke. Any of the larger projects -- and nobody is building a project anywhere close to FGPP on petcoke, but even the 300-megawatt projects are trying to be designed next to or within a refinery in order to assure a committed supply.

MR. GROSS: Just one moment. I think I'm

done.

That concludes my questioning. Thank you, Mr. Schwartz.

CHAIRMAN EDGAR: Mr. Krasowski, do you have questions for this witness?

MR. KRASOWSKI: Yes, ma'am.

CROSS-EXAMINATION

BY MR. KRASOWSKI:

Q. Good afternoon, Mr. Schwartz.

A. Good afternoon.

Q. Mr. Schwartz, regarding your testimony in regards to IGCC, when do you believe IGCC might be available at a size of even half the size of the FGPP plant in commercial dependable operational, 90 percent, 80 percent?

A. I don't have a specific date to give you. You know, I would say it's not available at the present time. I don't have a date that I'm projecting when it would be available.

Q. Now, in your analysis, did you consider the availability of sequestration technology along with IGCC in comparison to the Glades Power Park capability to sequester, if and when that ever happens?

MS. SMITH: Madam Chairman, I think these questions may be better addressed, or at least this one, better addressed to other FPL witness, perhaps Mr. Jenkins and Mr. Kosky.

MR. KRASOWSKI: This is included in the gentleman's testimony, but if that would be better, I'll defer to Mr. Jenkins if he's here.

MS. SMITH: Well, if the witness can answer.

CHAIRMAN EDGAR: The witness can answer if the witness can answer.

MR. KRASOWSKI: Excuse me.

A. I'm sorry. That wasn't an area that I've looked at, no.

Q. The sequestration?

A. The sequestration, no.

Q. Okay. Fine. You did look at transportation?

A. Yes.

Q. Okay. Did you analyze the condition of the train tracks that go to and run along the proposed site? It's my understanding they're in very poor condition and can't handle the weight of it. So if you have analyzed it -- have you analyzed it?

A. No. The condition of the tracks is not something that was personally under my area. I was dealing with the long haul rail costs. I understand that there is upgrading the project will do and the local supplying railroad, the South Central Florida

Express, will do as part of this project. I suspect Mr. Hicks is probably the right person to ask about that.

MR. KRASOWSKI: Okay. Thank you. I'll do that. And that concludes my questions of Mr. Schwartz. Thank you.

CHAIRMAN EDGAR: Thank you. Commissioners? Are there questions from staff?

MS. BRUBAKER: Staff has none.

CHAIRMAN EDGAR: Okay. Redirect?

MS. SMITH: No redirect.

CHAIRMAN EDGAR: Okay. Then seeing no objections we will enter Exhibits 73 through 92 and 135 through 146 into the record.

(Exhibits 73 through 92 and 135 through 146 admitted into the record.)

CHAIRMAN EDGAR: The witness is excused.

THE WITNESS: Thank you.

CHAIRMAN EDGAR: Thank you. Mr. Gross, I believe that what we had agreed to earlier is that you would call your witness next.

MR. GROSS: Yes. Thank you.

MR. KRASOWSKI: Excuse me, Madam Chair.

CHAIRMAN EDGAR: Mr. Krasowski.

MR. KRASOWSKI: Maybe I'm a bit confused, but

Mr. Brandt is not going next, but someone else is?

CHAIRMAN EDGAR: We are going to take up Mr. Schlissel. And I am so sorry that with my lisp I can't get that out correctly.

MR. KRASOWSKI: That sounds good. And then will we go to Mr. Brandt if there's time?

CHAIRMAN EDGAR: If there's time today.

MR. KRASOWSKI: Okay. And we're closing at 5:30?

CHAIRMAN EDGAR: Between 5:00 and 5:30 is my goal.

MR. KRASOWSKI: Okay.

MR. GROSS: Madam Chair, if you recall, we mentioned yesterday that Mr. Schlissel was making some corrections to his supplemental direct, and at this time we would like to pass out copies that were filed this morning and the errata sheet that goes with it.

CHAIRMAN EDGAR: Okay. Yes, please.

MS. BRUBAKER: Madam Chairman.

CHAIRMAN EDGAR: Ms. Brubaker.

MS. BRUBAKER: If I've missed this, my apologies, but has this been identified already?

CHAIRMAN EDGAR: This has not been identified. Do we need to do that?

MS. BRUBAKER: I would suggest in order to be consistent with FPL's errata sheet that it be so. But I'll leave that to Mr. Gross.

CHAIRMAN EDGAR: Well, once again, we strive for clarity, so let me get there.

So we will need to, as you said, for consistency, mark the errata sheet. And what about the corrected supplemental testimony? Does that travel together as one, or has this been prefiled?

Mr. Litchfield, can you help me?

MR. LITCHFIELD: Madam Chairman, my recommendation is just to mark and then enter the errata sheet. The supplemental testimony that has already been filed I think can be entered in conjunction with the errata into the record as though read.

CHAIRMAN EDGAR: Does that work for you, Mr. Gross?

MR. GROSS: That's works.

CHAIRMAN EDGAR: Ms. Brubaker?

MS. BRUBAKER: Yes. Thank you.

CHAIRMAN EDGAR: So I am on 162.

(Exhibit 162 marked for identification.)

MR. GROSS: I just want to make sure that Mr. Schlissel has copies of the errata sheet --

THE WITNESS: No, I don't have the errata sheet.

MR. GROSS: -- and the corrected --

CHAIRMAN EDGAR: Are we out of copies?

MR. GROSS: We came up one copy short.

CHAIRMAN EDGAR: I'll bet our staff can share.

MR. GROSS: Thank you.

THE WITNESS: I don't really need them. I wrote them.

CHAIRMAN EDGAR: It would be best if you have it in front you of you, but I appreciate that.

THE WITNESS: Thank you very much.

CHAIRMAN EDGAR: Okay. Mr. Gross, I think we're ready.

Thereupon,

DAVID A. SCHLISSEL

was called as a witness on behalf of Sierra Club, Save Our Creeks, Florida Wildlife Federation, Environmental Confederation of Southwest Florida, and Ellen Peterson, and having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. GROSS:

Q. Mr. Schlissel, please state your full name and business address.

A. My name is David A. Schlissel, S-c-h-l-i-s-s-e-l. My business address is Synapse Energy Economics, 22 Pearl Street, Cambridge, Massachusetts, ZIP, 02139.

Q. Okay. Mr. Schlissel, did you cause to be filed on March 16, 2007, corrected direct testimony and exhibits consisting -- well, the testimony consisting of 23 pages?

A. Yes.

Q. And did you sponsor Exhibits DAS-1 through 4?

A. Yes.

Q. Did ou file corrected supplemental direct on April 17th, 2007?

A. Yes.

Q. Consisting of 15 pages?

A. Yes.

Q. Do you have any corrections or revisions to your corrected direct testimony or your corrected supplemental direct testimony?

A. I'm sorry. I'm confused. The version of the corrected supplemental testimony I prepared had bold and underlining for each of the corrections. The version that I have in front me does not have that. I guess it's on the errata.

Q. Right. The changes are on the errata.

A. Those are the changes. I don't have any additional changes, no.

Q. Okay. Thank you. If you were asked the same questions today that you were asked in preparing your direct, original direct testimony and your supplemental direct testimony, would your answers be the same.

A. Yes.

MR. GROSS: I would move that Mr. Schlissel's corrected direct testimony dated March 16, 2007, with Exhibits DAS-1 through DAS-4 and his corrected supplemental direct testimony consisting of 15 pages and dated April 17th, 2007, be inserted into the record as though read.

CHAIRMAN EDGAR: Any objection?

MR. LITCHFIELD: Maybe just a clarification. I thought I understood him to suggest that the exhibits be inserted into the record as though read.

CHAIRMAN EDGAR: He did, which would be Exhibits 126 through 129, plus then the just-marked errata sheets. I think what we can do is go ahead and, if there is no objection, Mr. Litchfield, enter the prefiled direct testimony into the record with the corrections that have been noted, and then just per as we have been doing, we will take up the exhibits at the end of the testimony.

I. Identification and Qualifications

Q: State your name, occupation and business address.

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics ("Synapse") is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government and utilities. A complete description of Synapse is available at our website, www.synapse-energy.com.

Q. Please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 28 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My clients have included the Staff of the Arizona Corporation Commission, the General Staff of the Arkansas Public Service Commission, the Staff of the Kansas State Corporation Commission, municipal utility systems in

Massachusetts, New York, Texas, and North Carolina, and the Attorney General of the Commonwealth of Massachusetts.

I have testified before state regulatory commissions in Arizona, New Jersey, Connecticut, Kansas, Texas, New Mexico, New York, Vermont, North Carolina, South Carolina, Maine, Illinois, Indiana, Ohio, Massachusetts, Missouri, Rhode Island, Wisconsin, Iowa, South Dakota, Georgia, Minnesota and Michigan and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is attached as Exhibit DAS-1.

II. Introduction and Summary

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Sierra Club, Inc., Florida Wildlife Federation (FWF), Save Our Creeks (SOC), the Environmental Confederation of Southwest Florida (ECOSWF) and Ellen Peterson.

Q. What is the purpose of this Direct Testimony?

A. Synapse has been asked to evaluate Florida Power & Light Company's ("FPL") justification for the proposed Glade Power Park Units 1 and 2 based on the information provided in FPL's Petition and supporting testimony. This Direct Testimony presents the results of our evaluation of the likely future costs that will result from greenhouse gas emission regulations/restrictions.

III. Federally Mandated Greenhouse Gas Emission Reductions can be Expected in the Near Future

Q. Is it prudent to expect that a policy to address climate change will be implemented in the U.S. in a way that should be of concern to utilities building new coal plants?

A. Yes. The prospect of global warming and the resultant widespread climate changes has spurred international efforts to work towards a sustainable level of greenhouse gas emissions. These international efforts are embodied in the

United Nations Framework Convention on Climate Change ("UNFCCC"), a treaty that the U.S. ratified in 1992, along with almost every other country in the world. The Kyoto Protocol, a supplement to the UNFCCC, establishes legally binding limits on the greenhouse gas emissions of industrialized nations and economies in transition.

Despite being the single largest contributor to global emissions of greenhouse gases, the United States remains one of a very few industrialized nations that have not signed the Kyoto Protocol.[1] Nevertheless, individual states, regional groups of states, shareholders and corporations are making serious efforts and taking significant steps towards reducing greenhouse gas emissions in the United States. Efforts to pass federal legislation addressing carbon, though not yet successful, have gained ground in recent years. These developments, combined with the growing scientific understanding of, and evidence of, climate change mean that establishing federal policy requiring greenhouse gas emission reductions is just a matter of time. The question is not whether the United States will develop a national policy addressing climate change, but when and how. The electric sector will be a key component of any regulatory or legislative approach to reducing greenhouse gas emissions both because of this sector's contribution to national emissions and the comparative ease of regulating large point sources.

There are, of course, important uncertainties with regard to the timing, the emission limits, and many other details of what a carbon policy in the United States will look like.

[1] As I use the terms "carbon dioxide regulation" and "greenhouse gas regulation" throughout our testimony, there is no difference. While I believe that the future regulation we discuss here will govern emissions of all types of greenhouse gases, not just carbon dioxide ("CO2"), for the purposes of our discussion we are chiefly concerned with emissions of carbon dioxide. Therefore, I use the terms "carbon dioxide regulation" and "greenhouse gas regulation" interchangeably. Similarly, the terms "carbon dioxide price," "greenhouse gas price" and "carbon price" are interchangeable.

In this case, though, the best evidence of this is the simple fact that FPL is requesting PSC approval to recover environmental compliance costs associated with the Glades Power Park.

Q. If the Glades Power Park Project were to be built, is carbon regulation an issue that could be reasonably dealt with in the future, once the timing and stringency of the regulation is known?

A. Unfortunately, no. Unlike for other power plant air emissions like sulfur dioxide and oxides of nitrogen, there currently is no commercial or economical method for post-combustion removal of carbon dioxide from ultra-supercritical pulverized coal plants. FPL agrees on that point. At page 26, lines 16-18 of his testimony, Stephen Jenkins says "Similar R&D is proceeding for CO_2 capture technology that could be applied to PC plants. Applying CO_2 capture to a PC plant is presently much more difficult and expensive than for an IGCC plant."

Q. How does FPL view the prospects for carbon regulation?

A. FPL Group, FPL's parent company, has signed on to numerous agreements endorsing the need to address climate change. Most recently, it endorsed the Joint Statement of the Global Roundtable on Climate Change (GROCC). The statement urges:

- Scientifically informed targets…for "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."
- Clear, efficient mechanisms to place a market price on carbon emissions.
- Government policy initiatives to address energy efficiency and de-carbonization in all sectors
- Signatories to this statement will support scientific processes including the Intergovernmental Panel on Climate Change; work to increase public

awareness of climate change risks and solutions; report information on their GHG emissions, engage in GHG emissions mitigation; which can include emissions trading schemes; champion demonstration projects; and support public policy efforts to mitigate climate change and its impacts.

FPL Group has also joined the high profile U.S. Climate Action Partnership ("US CAP") which advocates for federal, mandatory legislation of greenhouse gases. The six principles of the groups are:

- Account for the global dimensions of climate change;
- Create incentives for technology innovation;
- Be environmentally effective;
- Create economic opportunity and advantage;
- Be fair to sectors disproportionately impacted; and
- Reward early action.

These are only two examples of FPL Group's activities with respect to climate change, but taken together, partnerships such as US CAP and public statements by FPL Group imply that the Company is at least aware of the problem of climate change and knows that climate change regulation is not just an environmental issue; it is also a consumer issue.

Q. Do other utilities have opinions about whether and when greenhouse gas regulation will come?

A. Yes. A number of utility executives have argued that mandatory federal regulation of the emissions of greenhouse gases is inevitable.

For example, in April 2006, the Chairman of Duke Energy, Paul Anderson, stated:

> From a business perspective, the need for mandatory federal policy in the United States to manage greenhouse gases is both urgent and real. In my view, voluntary actions will not get us where we need to be. Until business leaders know what the rules will be – which actions will be penalized and which will be rewarded – we will be unable to take the significant actions the issue requires.[2]

Similarly, James Rogers, who was the CEO of Cinergy and is currently CEO of Duke Energy, has publicly said "[I]n private, 80-85% of my peers think carbon regulation is coming within ten years, but most sure don't want it now."[3] Mr. Rogers also was quoted in a December 2005 *Business Week* article, as saying to his utility colleagues, "If we stonewall this thing [carbon dioxide regulation] to five years out, all of a sudden the cost to us and ultimately to our consumers can be gigantic."[4]

Not wanting carbon regulation from a utility perspective is understandable because carbon price forecasting is not simple and easy, it makes resource planning more difficult and is likely to change "business as usual." For many utilities, including FPL, that means that it is much more difficult to justify building a pulverized coal plant. Regardless, it is imprudent to ignore the risk.

Duke Energy is not alone in believing that carbon regulation is inevitable and, indeed, some utilities are advocating for mandatory greenhouse gas reductions. In a May 6, 2005, statement to the Climate Leaders Partners (a voluntary EPA-industry partnership), John Rowe, Chair and CEO of Exelon stated, "At Exelon, we accept that the science of global warming is overwhelming. We accept that limitations on greenhouse gases emissions [sic] will prove necessary. Until those

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[2] Paul Anderson, Chairman, Duke Energy, "Being (and Staying in Business): Sustainability from a Corporate Leadership Perspective," April 6, 2006 speech to CERES Annual Conference, at: http://www.duke-energy.com/news/mediainfo/viewpoint/PAnderson_CERES.pdf

[3] "The Greening of General Electric: A Lean, Clean Electric Machine," *The Economist,* December 10, 2005, at page 79.

[4] "The Race Against Climate Change," *Business Week*, December 12, 2005, online at http://businessweek.com/magazine/content/05_50/b3963401.htm.

limitations are adopted, we believe that business should take voluntary action to begin the transition to a lower carbon future."

In fact, several electric utilities and electric generation companies have incorporated assumptions about carbon regulation and costs into their long term planning, and have set specific agendas to mitigate shareholder risks associated with future U.S. carbon regulation policy. These utilities cite a variety of reasons for incorporating risk of future carbon regulation as a risk factor in their resource planning and evaluation, including scientific evidence of human-induced climate change, the U.S. electric sector's contribution to emissions, and the magnitude of the financial risk of future greenhouse gas regulation.

Some of the companies believe that there is a high likelihood of federal regulation of greenhouse gas emissions within their planning period. For example, Pacificorp states a 50% probability of a CO_2 limit starting in 2010 and a 75% probability starting in 2011. The Northwest Power and Conservation Council models a 67% probability of federal regulation in the twenty-year planning period ending 2025 in its resource plan. Northwest Energy states that CO_2 taxes "are no longer a remote possibility."[5]

Even those in the electric industry who oppose mandatory limits on greenhouse gas regulation believe that regulation is inevitable. David Ratcliffe, CEO of Southern Company, a predominantly coal-fired utility that opposes mandatory limits, said at a March 29, 2006, press briefing that "There certainly is enough public pressure and enough Congressional discussion that it is likely we will see some form of regulation, some sort of legislation around carbon."[6]

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5 Northwest Energy 2005 Electric Default Supply Resource Procurement Plan, December 20, 2005; Volume 1, p. 4.

6 Quoted in "U.S. Utilities Urge Congress to Establish CO2 Limits," Bloomberg.com, http://www.bloomberg.com/apps/news?pid=10000103&sid=a75A1ADJv8cs&refer=us

Q. Why would electric utilities, in particular, be concerned about future carbon regulation?

A. Electricity generation is very carbon-intensive. Electric utilities are likely to be one of the first, if not the first, industries subject to carbon regulation because of the relative ease in regulating stationary sources as opposed to mobile sources (automobiles) and because electricity generation represents a significant portion of total U.S. greenhouse gas emissions. A new generating facility may have a book life of twenty to forty years, but in practice, the utility may expect that that asset will have an operating life of 50 years or more. By adding new plants, especially new coal plants, a utility is essentially locking-in a large quantity of carbon dioxide emissions for decades to come. In general, electric utilities are increasingly aware that the fact that we do not currently have federal greenhouse gas regulation is irrelevant to the issue of whether we will in the future, and that new plant investment decisions are extremely sensitive to the expected cost of greenhouse gas regulation throughout the life of the facility.

Q. Do others in the private sector, besides electric utilities, also believe that regulation of greenhouse gases is inevitable?

A. Yes. Corporate leaders, investors, financial analysts and major corporations are increasingly anticipating and preparing for requirements to reduce greenhouse gas emissions.[7] For example, a recent survey of 31 multinational corporations by the Pew Center on Global Climate Change found that 90 percent expect the U.S. government to set standards for greenhouse gas emissions imminently.[8] About 18 percent believe that federal standards will take effect before 2010: another 67 percent believe those standards will take effect between 2010 and 2015.[9]

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7 Exhibit DAS-3, at pages 34 of 63 to 37 of 63.

8 http://www.pewclimate.org/docUploads/PEW%5FCorpStrategies%2Epdf, at page 1.

9 Ibid.

Investors and investment analysts also are anticipating the imminent establishment of federally mandated reductions in greenhouse gas emissions. For example, in October 2004, Fitch Ratings reported that over the next ten years, it expected that:

> the power industry to face higher environmental standards for sulfur dioxide (SO_2), nitrogen oxide (NO_x) and mercury, as well as new rules for the emissions of greenhouse gases (GHGs). As the scientific debate has moved from the topic of "whether global warming exists) to a discussion of the magnitude of the problem, concerns about GHGs have expanded to a wider audience. Investors and insurance companies are becoming increasingly concerned about the financial effects of future environmental regulations on the power sector as a primary emitter of GHGs. Requirements to control the sources of global warming and enhanced regulation of other pollutants could increase the financial liability of coal-dependent power producers, thereby leading to lower returns and lower post-investment cash generation.[10]

Fitch Ratings has more recently been quoted as telling industry representatives that it believes that a federal law to cap CO_2 emissions is "imminent" and that "compliance costs could have a significant effect on the credit profiles of generators."[11]

Q. Have mandatory greenhouse gas emissions reductions programs begun to be examined and debated in the U.S. federal government?

A. To date, the U.S. government has not required greenhouse gas emission reductions. However, a number of legislative initiatives for mandatory emissions reduction proposals have been introduced in Congress. These proposals establish carbon dioxide emission trajectories below the projected business-as-usual emission trajectories, and they generally rely on market-based mechanisms (such as cap and trade programs) for achieving the targets. The proposals also include

[10] *Status of Environmental Regulation*, Fitch Ratings Corporate Finance, October 12, 2004.

[11] *CO2 Trading Plan could cost US utilities $6bil/year: Fitch*, Platts, 7Nov2006,

various provisions to spur technology innovation, as well as details pertaining to offsets, allowance allocation, restrictions on allowance prices and other issues. Through their consideration of these proposals, legislators are increasingly educated on the complex details of different policy approaches, and they are laying the groundwork for a national mandatory program. The federal proposals that would require greenhouse gas emission reductions that had been submitted in Congress through early February 2007 are summarized in Table 1 below.

Table 1. Summary of Mandatory Emissions Targets in Proposals Discussed in Congress[12]

Proposed National Policy	Title or Description	Year Proposed	Emission Targets	Sectors Covered
McCain Lieberman S.139	Climate Stewardship Act	2003	Cap at 2000 levels 2010-2015. Cap at 1990 levels beyond 2015.	Economy-wide, large emitting sources
McCain Lieberman SA 2028	Climate Stewardship Act	2003	Cap at 2000 levels	Economy-wide, large emitting sources
National Commission on Energy Policy (basis for Bingaman-Domenici legislative work)	Greenhouse Gas Intensity Reduction Goals	2005	Reduce GHG intensity by 2.4%/yr 2010-2019 and by 2.8%/yr 2020-2025. Safety-valve on allowance price	Economy-wide, large emitting sources
Jeffords S. 150	Multi-pollutant legislation	2005	2.050 billion tons beginning 2010	Existing and new fossil-fuel fired electric generating plants > 15 MW
Carper S. 843	Clean Air Planning Act	2005	2006 levels (2.655 billion tons CO_2) starting in 2009, 2001 levels (2.454 billion tons CO_2) starting in 2013.	Existing and new fossil-fuel fired, nuclear, and renewable electric generating plants > 25 MW
Feinstein	Strong Economy and Climate Protection Act	2006	Stabilize emissions through 2010; 0.5% cut per year from 2011-15; 1% cut per year from 2016-2020. Total reduction is 7.25% below current levels.	Economy-wide, large emitting sources
Rep. Udall - Rep. Petri	Keep America Competitive Global Warming Policy Act	2006	Establishes prospective baseline for greenhouse gas emissions, with safety valve.	Energy and energy-intensive industries

12 More detailed summaries of the bills that have been introduced in the U.S. Senate in the 110th Congress are presented in Exhibit DAS-2.

Carper S.2724	Clean Air Planning Act	2006	2006 levels by 2010, 2001 levels by 2015	Existing and new fossil-fuel fired, nuclear, and renewable electric generating plants > 25 MW
Kerry and Snowe S.4039	Global Warming Reduction Act	2006	No later than 2010, begin to reduce U.S. emissions to 65% below 2000 levels by 2050	Not specified
Waxman H.R. 5642	Safe Climate Act	2006	2010 – not to exceed 2009 level, annual reduction of 2% per year until 2020, annual reduction of 5% thereafter	Not specified
Jeffords S. 3698	Global Warming Pollution Reduction Act	2006	1990 levels by 2020, 80% below 1990 levels by 2050	Economy-wide
Feinstein- Carper S.317	Electric Utility Cap & Trade Act	2007	2006 level by 2011, 2001 level by 2015, 1%/year reduction from 2016-2019, 1.5%/year reduction starting in 2020	Electricity sector
Kerry-Snowe	Global Warming Reduction Act	2007	2010 level from 2010-2019, 1990 level from 2020-2029, 2.5%/year reductions from 2020-2029, 3.5%/year reduction from 2030-2050, 65% below 2000 level in 2050	Economy-wide
McCain-Lieberman S.280	Climate Stewardship and Innovation Act	2007	2004 level in 2012, 1990 level in 2020, 20% below 1990 level in 2030, 60% below 1990 level in 2050	Economy-wide
Sanders-Boxer S.309	Global Warming Pollution Reduction Act	2007	2%/year reduction from 2010 to 2020, 1990 level in 2020, 27% below 1990 level in 2030, 53% below 1990 level in 2040, 80% below 1990 level in 2050	Economy-wide
Olver, et al HR 620	Climate Stewardship Act	2007	Cap at 2006 level by 2012, 1%/year reduction from 2013-2020, 3%/year reduction from 2021-2030, 5%/year reduction from 2031-2050, equivalent to 70% below 1990 level by 2050	US national
Sen. Bingaman – Discussion draft		As of 1/11/2007	2.6%/year reduction in emissions intensity from 2012-2021, 3%/year reduction starting in 2022	Economy-wide

Q. Is it reasonable that the potential for passage of greenhouse gas regulations have improved as a result of the recent federal elections?

A. Yes. Although there are increasing numbers of Republican legislators who recognize the need for legislation to regulate the emissions of greenhouse gases, the results of the recent elections, in which control of both Houses of Congress shifted to Democrats, are likely to improve the chances for near-term passage of significant legislation. For example, experts at an industry conference right after the elections expressed the opinion that now that Democrats have won control of Congress, electric utilities should expect a strong legislative push for mandatory caps on carbon dioxide emissions.[13]

Senator McCain also has indicated that he believed that the chances of Congress approving meaningful global warming legislation before 2008 were "pretty good" and that he believed that "we've reached a tipping point in this debate, and its long overdue."[14]

At the same time, Senators Bingaman, Boxer and Lieberman sent a letter to President Bush on November 14, 2006, seeking the President's commitment to work with the new Congress to pass meaningful climate change legislation in 2007.[15] Senators Bingaman, Boxer and Lieberman in January are the chairpersons of, respectively, the Senate Energy and Natural Resources Committee, the Senate Environment and Public Works Committee and the Senate Homeland Security and Governmental Affairs Committee in the current Congress.

Nevertheless, our conclusion that significant greenhouse gas regulation is inevitable is not based on the results of any single election or on the fate of any single bill introduced in Congress.

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13 *Mandatory US carbon caps coming following elections: observers*, Platts 9Nov2006.

14 Ibid.

15 Ibid.

Q. Have recent polls indicated that the American people are increasingly in favor of government action to address global warming concerns?

A. Yes. A summer 2006 poll by Zogby International showed that an overwhelming majority of Americans are more convinced that global warming is happening than they were even two years ago, and they are also connecting intense weather events like Hurricane Katrina and heat waves to global warming.[16] Indeed, the poll found that 74% of all respondents, including 87% of Democrats, 56% of Republicans and 82% of Independents, believe that we are experiencing the effects of global warming.

The poll also indicated that there is strong support for measures to require major industries to reduce their greenhouse gas emissions to improve the environment without harming the economy – 72% of likely voters agreed such measures should be taken.[17]

Other recent polls reported similar results. For example, a Time/ABC/Stanford University poll issued in the spring found 68 percent of Americans are in favor of more government action.[18] In addition, a September 2006 telephone poll, conducted by NYU's Brademas Center for the Study of Congress, reported that 70% of those polled stated that they were worried about global warming.[19]

At the same time, according to a recent public opinion survey for the Massachusetts Institute of Technology, Americans now rank climate change as the country's most pressing environmental problem—a dramatic shift from three years ago, when they ranked climate change sixth out of 10 environmental

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16 "Americans Link Hurricane Katrina and Heat Wave to Global Warming," Zogby International, August 21, 2006, available at www.zogby.com/news.

17 Ibid.

18 "Polls find groundswell of belief in, concern about global warming." Greenwire, April 21, 2006, Vol. 10 No. 9. See also Zogby's final report on the poll which is available at http://www.zogby.com/wildlife/NWFfinalreport8-17-06.htm.

19 Kaplun, Alex: "Campaign 2006: Most Americans 'worried' about energy, climate;" Greenwire, September 29, 2006.

concerns.[20] Almost three-quarters of the respondents felt the government should do more to deal with global warming, and individuals were willing to spend their own money to help.

IV. State and Regional Actions

Q. Are any states developing and implementing climate change policies that will have a bearing on resource choices in the electric sector?

A. Yes. States continue to be the leaders and innovators in developing and implementing policies that will affect greenhouse gas emissions.

On August 30, 2006, Governor Schwarzenegger and the California Legislature reached an agreement on AB32, the Global Warming Solutions Act.[21] The Act creates an economy-wide cap on greenhouse gas emissions and includes penalties for non-compliance. The cap limits California's greenhouse gas emissions at 1990 levels by 2020. This is the first state to adopt a mandatory economy-wide greenhouse gas emissions limit. California has also adopted a law, SB 1368, directing the California Energy Commission to set a greenhouse gas performance standard for electricity procured by local publicly owned utilities, whether it is generated within state borders or imported from plants in other states. The standard is to be adopted by June 30, 2007 and will apply to all new long-term electricity contracts. California is also exploring coordination of its statewide greenhouse gas reduction program with the Northeast's Regional Greenhouse Gas Initiative.

[20] *MIT Carbon Sequestration Initiative, 2006 Survey,* http://sequestration.mit.edu/research/survey2006.html

[21] Governor Schwarzenegger press release, August 30, 2006. http://gov.ca.gov/index.php?/press-release/3722/. Pew Center on Climate Change, "Latest News" from the states http://www.pewclimate.org/what_s_being_done/in_the_states/news.cfm

Similarly, in September 2006, the Governor of Arizona issued an Executive Order (2006-13) establishing a statewide goal to reduce Arizona's greenhouse gas emissions to 2000 levels by 2020, and 50% below this level by 2040.[22]

Other states have indirect policies that will impact future emissions of greenhouse gases. These indirect policies include the requirements by various states to either consider future carbon dioxide regulation or use specific "adders" for carbon dioxide in resource planning. They also include policies and incentives to increase energy efficiency and renewable energy use, such as renewable portfolio standards. Some of these requirements are at the direction of state public utilities commissions, others are statutory requirements.

But states are not just acting individually; there are a number of examples of innovative regional policy initiatives that range from agreeing to coordinate information (e.g., Southwest governors and Midwestern legislators) to development of a regional cap and trade program through the Regional Greenhouse Gas Initiative in the Northeast ("RGGI"). The objective of the RGGI is the stabilization of CO_2 emissions from power plants at current levels for the period 2009-2015, followed by a 10 percent reduction below current levels by 2019.[23]

In an effort that could provide an important foundation for implementation of a national cap on greenhouse gases, representatives of 30 states have begun discussions of a multi-state climate action registry. This effort builds on existing registries in the Northeast and California. The group is discussing development

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22 Governor Napolitano Press release, September 8, 2006.
http://azgovernor.gov/dms/upload/NR_090806_CCAG.pdf

Pew Center on Climate Change, "Latest News" from the states
http://www.pewclimate.org/whats_being_done/in_the_states/news.cfm

23 Table 5.5 of Exhibit DAS-3, at page 32 of 63.

of common accounting practices and development of an internet-based monitoring system for voluntary and mandatory greenhouse gas reporting.[24]

Q. Have any states adopted direct policies that require specific emissions reductions from electric sources?

A. Yes. The states of Massachusetts, New Hampshire, Oregon and California have adopted policies requiring greenhouse gas emission reductions from power plants.[25]

Q. Do any states require that utilities or default service suppliers evaluate costs or risks associated with greenhouse gas emissions in long-range planning or resource procurement?

A. Yes. As shown in Table 2 below, several states require companies to account for the emission of greenhouse gases in resource planning.

Table 2. Requirements for Consideration of Greenhouse Gas Emissions in Electric Resource Decisions

Program type	State	Description	Date	Source
GHG value in resource planning	CA	PUC requires that regulated utility IRPs include carbon adder of $8/ton CO_2, escalating at 5% per year.	April 1, 2005	CPUC Decision 05-04-024
GHG value in resource planning	WA	Law requiring that cost of risks associated with carbon emissions be included in Integrated Resource Planning for electric and gas utilities	January, 2006	WAC 480-100-238 and 480-90-238
GHG value in resource planning	OR	PUC requires that regulated utility IRPs include analysis of a range of carbon costs	Year 1993	Order 93-695
GHG value in resource planning	NWPCC	Inclusion of carbon tax scenarios in Fifth Power Plan	May, 2006	NWPCC Fifth Energy Plan
GHG value in resource planning	MN	Law requires utilities to use PUC established environmental externalities values in resource planning	January 3, 1997	Order in Docket No. E-999/CI-93-583
GHG in	MT	IRP statute includes an "Environmental	August 17,	Written Comments

24 O'Donnel, Arthur; "Thirty states discuss proposed emissions registry," Greenwire, October 4, 2006.

25 Table 5.3 of Exhibit DAS-3, at page 29 of 63.

resource planning		Externality Adjustment Factor" which includes risk due to greenhouse gases. PSC required Northwestern to account for financial risk of carbon dioxide emissions in 2005 IRP.	2004	Identifying Concerns with NWE's Compliance with A.R.M. 38.5.8209-8229; Sec. 38.5.8219, A.R.M.
GHG in resource planning	KY	KY staff reports on IRP require IRPs to demonstrate that planning adequately reflects impact of future CO_2 restrictions	2003 and 2006	Staff Report On the 2005 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company - Case 2005-00162, February 2006
GHG in resource planning	UT	Commission directs Pacificorp to consider financial risk associated with potential future regulations, including carbon regulation	June 18, 1992	Docket 90-2035-01, and subsequent IRP reviews
GHG in resource planning	MN	Commission directs Xcel to "provide an expansion of CO2 contingency planning to check the extent to which resource mix changes can lower the cost of meeting customer demand under different forms of regulation."	August 29, 2001	Order in Docket No. RP00-787

V. The Use of Carbon Dioxide Costs in Utility Planning

Q. What carbon dioxide values are being used by utilities in electric resource planning?

A. Table 3 below presents the carbon dioxide costs, in \$/ton CO_2, that are presently being used in the industry for both resource planning and modeling of carbon regulation policies.

Table 3. Carbon Dioxide Costs Used by Utilities

Company	CO2 emissions trading assumptions for various years ($2005)
PG&E*	$0-9/ton (start year 2006)
Avista 2003*	$3/ton (start year 2004)
Avista 2005	$7 and $25/ton (2010) $15 and $62/ton (2026 and 2023)
Portland General Electric*	$0-55/ton (start year 2003)
Xcel Energy-PSCCo	$9/ton (start year 2010) escalating at 2.5%/year
Idaho Power*	$0-61/ton (start year 2008)
Pacificorp 2004	$0-55/ton
Northwest Energy 2005	$15 and $41/ton
Northwest Power and Conservation Council	$0-15/ton between 2008 and 2016 $0-31/ton after 2016

**Values for these utilities from Wiser, Ryan, and Bolinger, Mark. "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans." Lawrence Berkeley National Laboratories. August 2005. LBNL-58450. Table 7.*
Other values: PacifiCorp, Integrated Resource Plan 2003, pages 45-46; and Idaho Power Company, 2004 Integrated Resource Plan Draft, July 2004, page 59; Avista Integrated Resource Plan 2005, Section 6.3; Northwestern Energy Integrated Resource Plan 2005, Volume 1 p. 62; Northwest Power and Conservation Council, Fifth Power Plan pp. 6-7. Xcel-PSCCo, Comprehensive Settlement submitted to the CO PUC in dockets 04A-214E, 215E and 216E, December 3, 2004. Converted to $2005 using GDP implicit price deflator.

Q. How should utilities plan for and mitigate the risk of greenhouse gas regulation?

A. The key part of that question is "plan for the risk of greenhouse gas regulation." Mitigating risk begins with the resource planning process and the decision as to the demand-side and supply-side options that should be pursued. A utility that chooses to go forward with a new, carbon intensive energy resource without proper consideration of carbon regulation is imprudent. To give an analogy it would be like choosing to build a gas-fired power plant without consideration of the cost of gas because one believes that building the plant is "worth it" regardless of what gas might cost.

A utility that desires to be prudent about the risk of carbon regulation would, at a minimum, consider carbon regulation by developing an expected carbon price forecast as well as reasonable sensitivities around that case.

Q. Has Synapse developed a carbon price forecast that would assist the Commission in evaluating FPL's Glades Power Park?

A. Yes. Our forecast is described in more detail in Exhibit DAS-3, starting on page 41 of 63.

During the decade from 2010 to 2020, we anticipate that a reasonable range of carbon emissions prices will reflect the effects of increasing public concern over climate change (this public concern is likely to support increasingly stringent emission reduction requirements) and the reluctance of policymakers to take steps that would increase the cost of compliance (this reluctance could lead to increased emphasis on energy efficiency, modest emission reduction targets, or increased use of offsets). We expect that the widest uncertainty in our forecasts will begin at the end of this decade, that is, from $10 to $40 per ton of CO_2 in 2020, depending on the relative strength of these factors.

After 2020, we expect the price of carbon emissions allowances to trend upward toward a marginal mitigation cost. This number will depend on currently uncertain factors such as technological innovation and the stringency of carbon caps, but it is likely that, by this time, the least expensive mitigation options (such as simple energy efficiency and fuel switching) will have been exhausted. Our projection for greenhouse gas emissions costs at the end of this decade ranges from $20 to $50 per ton of CO_2 emissions.

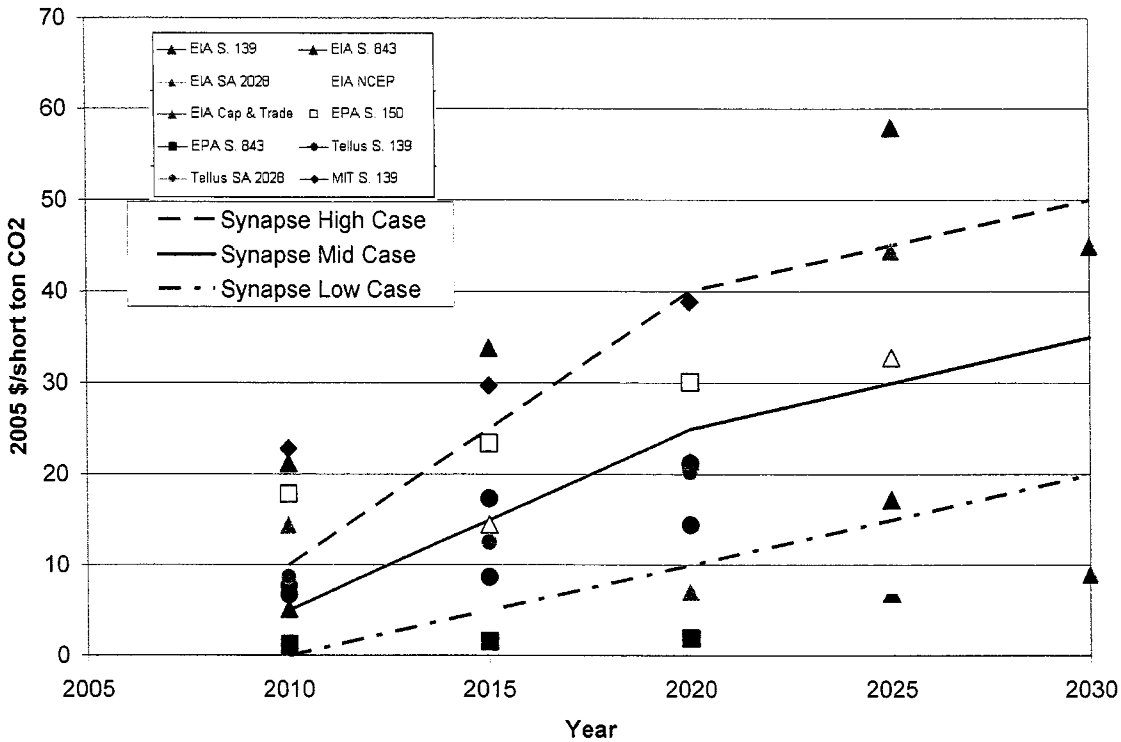
We currently believe that the most likely scenario is that as policymakers commit to taking serious action to reduce carbon emissions, they will choose to enact both cap and trade regimes and a range of complementary energy policies that lead to lower cost scenarios, and that technology innovation will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

After 2030, and possibly even earlier, the uncertainty surrounding a forecast of carbon emission prices will increase due to the interplay of factors such as the level of carbon constraints required and technological innovation. Scientists anticipate that very significant emission reductions will be necessary, in the range of 80 percent below 1990 emission levels, to achieve stabilization targets that will keep global temperature increases to a somewhat manageable level. As such, we believe there is a substantial likelihood that response to climate change impacts will require much more aggressive emission reductions than those contained in U.S. policy proposals, and in the Kyoto Protocol, to date. If the severity and certainty of climate change are such that emissions levels 70-80% below current rates are mandated, this could result in very high marginal emissions reduction costs, though we have not quantified the cost of such deeper cuts on a per ton basis.

Q. What is Synapse's forecast of carbon dioxide emissions prices?

A. Synapse's forecast of future carbon dioxide emissions prices are presented in Figure 1 below. This figure superimposes Synapse's forecast on the results of other cost analyses of proposed federal policies:

Figure 1. Synapse Carbon Dioxide Prices



Q. What is Synapse's levelized carbon price forecast?

A. Synapse's forecast, levelized[26] over 20 years, 2011 – 2030, is provided in Table 4 below.

Table 4. Synapse's Levelized Carbon Price Forecast (2005$/ton)

Low Case	Mid Case	High Case
$7.8	$19.1	$30.5

26 A value that is "levelized" is the present value of the total cost converted to equal annual payments. Costs are levelized in real dollars (i.e., adjusted to remove the impact of inflation).

Q. Do the Synapse carbon price forecasts presented in Tables 3 and 4 reflect the emission reduction targets in the bills that have been introduced in the current Congress?

A. No. We developed our price forecasts late last spring. These forecasts were based on the bills that had been introduced in Congress through that time and/or that had been analyzed by the EIA, EPA, MIT, etc. The bills that have been introduced in the current US Congress generally would mandate more stringent emissions reductions than the bills that we considered when we developed our carbon price forecasts. Consequently, we believe that our forecasts are conservative.

Q. How much additional CO_2 will the Glades Power Park Units 1 and 2 emit into the atmosphere?

A. At a projected 92 percent capacity factor , the Glades Power Park Units 1 and 2 will emit more than 14.5 million tons of CO2 annually.

Q. Would incorporating Synapse's carbon price forecast have a material effect on the economics of building and operating the proposed Glades Power Park Project?

A. Yes.

Q. What would be the annual CO_2 cost to FPL's Glades Power Park Applicants?

A. Assuming an 92% average annual capacity factor for the Glades Power Park Units, the range of annual, levelized cost to FPL of CO_2 regulation would be:

Low Case - 15,796,000 MWh · \$7.74/MWh = \$122,261,000

Mid Case - 15,796,000 MWh · \$19.60/MWh = \$309,602,000

High Case - 15,796,000 MWh · \$30.39/MWh = \$480,040,000

Q. Does this complete your testimony?

A. Yes. However, I anticipate submitting supplemental testimony on March 16, 2007.

Q. State your name, occupation and business address.

A. My name is David A. Schlissel. I am a Senior Consultant at Synapse Energy Economics, Inc, 22 Pearl Street, Cambridge, MA 02139.

Q. Are you the same David Schlissel that previously filed testimony in this docket?

A. Yes, I am.

Q. On whose behalf are you testifying?

A: My testimony is sponsored by the Sierra Club, Inc., Florida Wildlife Federation (FWF), Save Our Creeks (SOC), and the Environmental Confederation of Southwest Florida (ECOSWF) and Ellen Peterson.

Q. Please summarize this Supplemental Testimony.

A. My Direct Testimony filed on March 7, 2007 primarily provided Synapse's estimate of the likely cost arising from future greenhouse gas restrictions/reductions. The purpose of this Supplemental Testimony is to provide an FPL-specific context for those costs as well to critique FPL's resource planning in general.

Q. What have you discovered in the course of your review of FPL's resource planning?

A. On page 6, lines 5-8 of his testimony, FPL witness Rene Silva testifies "[G]iven the range of potential outcomes FPL is not recommending approval of FGPP based on any specific, projected set of assumptions or comparative economic results against other forms of generation." That is, FPL *recognizes* that the resource planning scenarios presented in its Need Study do *not* support the choice of FGPP.

FPL's major justification for FGPP can be summed up in four words "no new natural gas." However, that should not be enough to justify the building of a multi-billion dollar coal-fired generating facility. Instead, principles of least-cost, least-risk resource planning ought to compel FPL to justify FGPP on an economic basis. I would ask this Commission to very carefully consider whether building a 1,960 MW coal plant is an appropriate hedge against natural gas prices if the economics do not otherwise justify the building of that plant. I also would ask this Commission to consider whether the simple comparison between FGPP and natural gas generation that FPL has presented in its Need Study is appropriate. Finally, I will raise the issue of the justification for FPL's 20% reserve margin requirement.

Q. Can you please explain why FPL's analyses do not support the choice of FGPP versus natural gas generation?

A. FPL witness Silva has testified:[1]

> In 7 scenarios that generally reflect a wider fuel price differential between natural gas and coal and/or moderate environmental compliance costs, the Plan with Coal, which reflects the addition of FGPP results in lower costs (CPVRR) than would the plan without Coal. Conversely, in the 9 scenarios that generally reflect a narrower fuel price differential between natural gas and coal and/or higher environmental compliance costs, the Plan with Coal results in higher costs than the Plan without Coal.

The results of these scenarios are summarized in Table 1.

[1] Testimony of Rene Silva, page 32, lines 8-14.

Table 1. Cost Differentials of FPL Scenarios

	A – No CO_2	B – Low CO_2	C – Mid CO_2	D – High CO_2
High Differential	(2,792)	(2,045)	(1,127)	(666)
Shocked Differential	(873)	(113)	804	1,278
Medium Differential	(219)	537	1,466	1,930
Low Differential	1,912	2,670	3,604	4,037

A negative value indicates that the Plan with Coal is less expensive than the Plan without Coal.

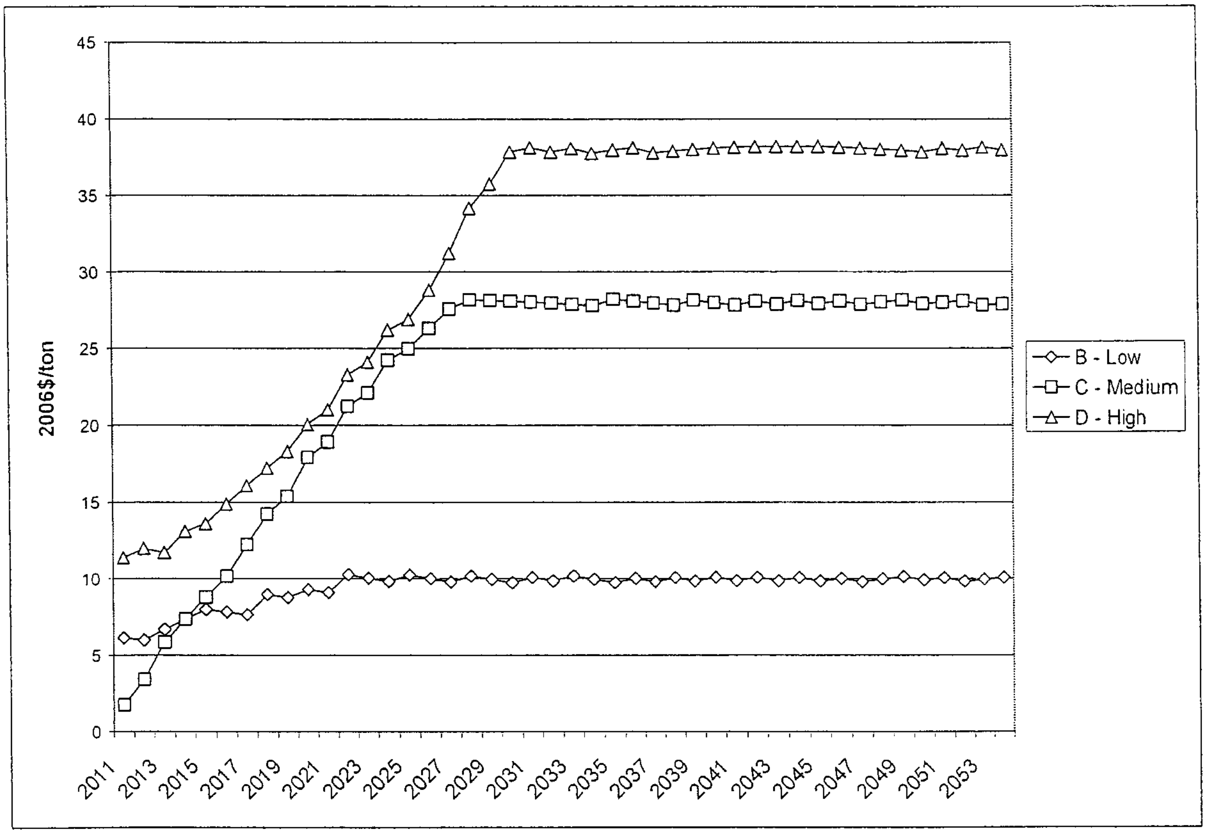
Perhaps not surprisingly, if the analysis does not consider the potential costs of CO_2 regulations, FGPP is a more economic option than the natural gas alternatives. But, as I discussed in my March 7th Direct Testimony, at this time the question of CO_2 regulation is not "if" but "when." Even FPL Group, as discussed in my March 7th testimony, concedes that action on climate change is necessary.

As a result, all of the scenarios in the left column in Table 1 above are not reasonable and should not be considered. That leaves the remaining twelve scenarios, of which only four show that FGPP is the lower cost option.

Q. Are these four remaining scenarios that show FGPP as the lower cost alternative reasonably likely?

A. No. FPL apparently evaluates these scenarios through the year 2054 which is to be commended given that FGPP is likely to have an operating life of at least 40 years. By the same token, FPL's environmental compliance forecasts must be evaluated for their reasonableness over the same period. I've taken the nominal CO_2 price forecasts supplied in Appendix F of the Need Study and converted them to real 2006 dollars using a 2.25% inflation rate to illustrate the real cost per ton of CO_2 under each forecast.

Figure 1. FPL CO_2 Price Forecasts (2006\$)



Forecast B, FPL's low CO2 price forecast, stands out as being just that, very low. Indeed, it is so low, that it is not reasonable to expect that such low CO_2 prices actually would lead to reductions in CO_2 emissions of sufficient magnitude to address the problem of climate change. In real dollars, the highest price this forecast would ever reach would be \$10/ton in 2022. Under all reasonable estimates I've seen, that would not be enough to incent carbon capture and sequestration at coal-fired power plants of any type, for example. Essentially, FPL's low forecast rests upon the assumption that U.S. greenhouse gas regulation will never result in significant reductions of greenhouse gas emissions. This is an unreasonable assumption over such a long period of time and therefore the scenarios assuming FPL's low forecast should not be considered.

That leaves us with just two out of eight scenarios (referring back to Table 1) which suggest that FGPP would be the lower cost capacity addition to FPL's system.

Q. Are these scenarios reasonable?

A. They may be. Certainly the real cost of CO_2 escalates to a much higher level than in the Company's low CO_2 price scenario. However, the CO_2 price in this scenario still tops out at only $28/ton. But, the more important question is whether the Commission's decision to grant FPL's need request ought to rest upon only these **two** reasonable planning scenarios.

Q. Should the Commission approve the building of FGPP based on the results of these two scenarios?

A. No. Even if we were to accept that the very limited comparison between FGPP and natural gas generation is the appropriate comparison, that is, that there are no other reasonable alternatives, the downside of building FGPP is, in most scenarios, much larger than the upside of moving forward with the project.

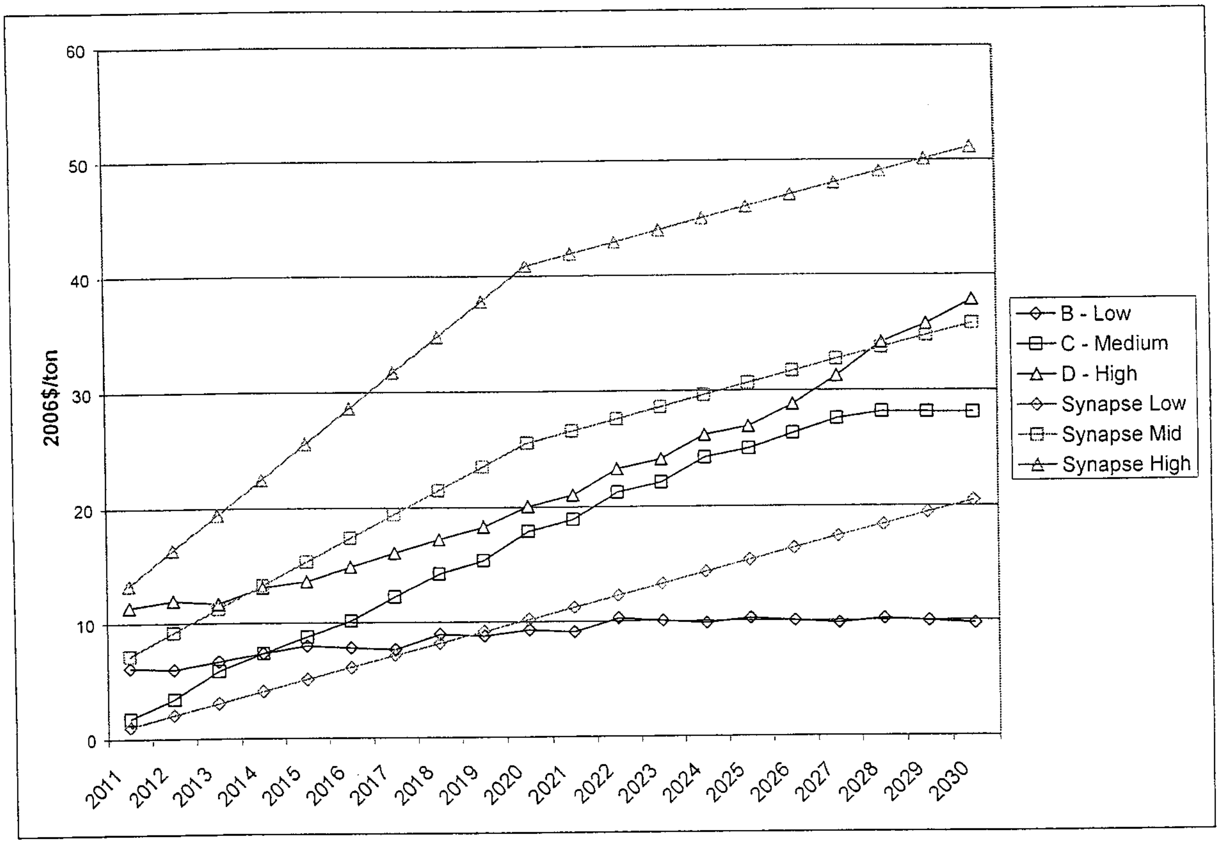
In the Mid-CO_2 Price, High Differential scenario, the upside of building FGPP rather than natural gas generation would be a cost savings to FPL customers of $1.127 billion. In the High-CO2 Price, High Difference scenario, the upside of building FGPP would be $666 million. In the other scenarios, however, it is *more* costly to FPL customers to go forward with FGPP in place of new natural gas-fired generation.

According to FPL's own analysis, as shown in Table 1 above, that cost could reach $4.037 billion.

Q. Is $4.037 billion the upper bound of the potential cost differential between FGPP and natural gas generation?

A. Not necessarily. My March 7, 2007 testimony presented Synapse's forecast of the cost of mandatory greenhouse gas reductions. Below, I've created a chart comparing our CO2 price forecast to that used by FPL in its economic analyses of the FGPP project.

Figure 2. Comparison of FPL CO_2 Forecast to Synapse Forecast



As you can see from Figure 2, even the FPL high CO2 price forecast is generally lower than the Synapse mid forecast. Under our Synapse mid and high CO_2 price forecasts, the cost to FPL's customers of proceeding with FGPP would rise significantly above $4.037 billion compared to natural gas generation.

Q. What is the basis for the CO_2 price forecasts used by FPL in its FGPP analyses?

A. According to FPL's response to Staff's First Set of Interrogatories, No. 35, the bills upon which these forecasts are based are:

- Senator Jeff Bingaman's Climate and Economy Insurance Act
- Senator Tom Carper's Clean Planning Act of 2006 (S.2724)

- Senator Dianne Feinstein Discussion Draft – Strong Economy and Climate Protection Act
- Senators John McCain & Joe Lieberman – Climate Stewardship Act (S.1151)

Some of these bills have evolved since then, including latest version of the McCain-Lieberman bill which has more aggressive emission reduction targets as introduced in 2007 compared to 2005. Most importantly, however, it would unreasonable to base a forecast of CO_2 allowance prices through 2054 on bills that do not address the need to stabilize the concentration of CO_2 in our atmosphere. *None* of these bills would achieve that.

Exhibit DAS-4[2] compares the emissions trajectories of several bills proposed in the 109th Congress including the Bingaman, Feinstein and McCain-Lieberman bills upon which FPL's forecasts are based. The Carper bill is, unfortunately, not included, but it is slightly less stringent than the McCain-Lieberman bill. The emission reduction paths to achieve stabilization targets of 550 parts per million (ppm) and 450 ppm are the grey lines. None of the bills upon which FPL relies, would come close to those targets.[3]

As with federal regulation of sulfur dioxide, I would expect federal regulation of carbon dioxide to come in steps. Over time, the regulation will become more

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2 The graphic in this exhibit is taken from the World Resource Institute and is available at http://www.wri.org/climate/topic_content.cfm?cid=4182.

3 Those are the lines "Bingaman (2005)," "McCain-Lieberman/Olver-Gilchrest (2005)," and "Feinstein (3/2006)."

stringent in order to address the problem of climate change. Such a trend, however, is apparently not reflected in FPL's CO_2 allowance forecasts.

Q. Does the comparison of fuel price differential and greenhouse gas regulation adequately capture the biggest risks to FGPP?

A. No, it does not. There are other major risks to building coal plants many of which FPL identifies in its Need Study at page 17. One of those risks it has not analyzed, however. That is the risk of increases in "the actual capital cost of completing FGPP and placing the generating units in commercial operation."

Q. Please describe this risk.

A. The projected costs of building new coal plants have increased dramatically over the past few years. This is due in large part to intense global competition for coal plants coupled with constrained supply. A perfect example comes from FGPP itself. At page 17, lines 17-23 of his testimony, FPL witness William Yeager says "The immense scope of this project, in the first instance, necessarily limits the number of potential EPC [engineer, procure, construct] contractors. Thus, the EPC pricing was based on an initial inquiry to three major contractors with coal engineering, procurement, construction experience. In fact, the result of this inquiry produced only one contractor with resources available in sufficient quantity to handle a project of this magnitude in the timeframe required."

It is remarkable that the EPC contract for such a large project could not be competitively bid and is an excellent example of why designers, vendors and suppliers can charge premiums on coal plant components and services of all types.

The demand for coal plants therefore translates into a significant cost risk for FGPP. At page 16 of the Need Study, FPL states "There are factors that could cause the capital cost of FGPP to be higher than projected. One reason for this is that there is a much longer lead time required, at least five and a half years from the date of this Need filing for development, permitting and construction of the first FGPP unit, compared to just over three years for gas-fired units, and a correspondingly greater opportunity for changes in the cost of equipment, labor and materials to occur."

Unfortunately, FPL has done no analysis under which it analyzed the effect of potential cost increases in the FGPP capital cost.

Q. Is it possible that FPL could mitigate both the downsides of new natural gas generation and FGPP?

A. Yes, mitigate and perhaps even avoid. Among the hundreds of pages of testimony and the Need Study, the glaring omission is information on how FPL even decided that its only two choices were FGPP or new natural gas generation. It is not enough for FPL to say that it needs to add 1,960 MW of new coal-fired capacity; it must justify that addition over other alternatives like renewables and energy efficiency (see the Testimony of John Plunkett) as well as demonstrate that baseload capacity is needed.

Q. Are you saying that there is no analysis showing how FPL arrived at the conclusion that it would need either gas or coal-fired baseload capacity?

A. Not that I have seen. In a need case such as this, I would expect to see a quantitative, economic analysis likely using a capacity expansion model to evaluate different resources. Instead, what FPL apparently has done is much simpler and excludes any sort of economic considerations.

Q. Please describe what you know about FPL's analysis.

A. FPL witness Steven Sim states at page 8, lines 20-21 of his testimony "FPL utilized its IRP process to first determine the timing and magnitude of resource needs." He does not describe at all what that process entails. However, on the page following he is asked the question "How did FPL decide it needed additional resources and what was the magnitude of the needed resources?" He answers:[4]

> FPL uses two analytical approaches in its reliability assessment to determine the timing and magnitude of its future resource needs…The first approach is to make projections of reserve margins both for Winter and Summer peak hours for future years. A minimum reserve margin criterion of 20% is used to judge the projected reserve margins.
>
> The second approach is a Loss-of-Load-Probability (LOLP) evaluation. Simply stated, LOLP is an index of how well a generating system may be able to meet its demand (i.e., a measure of how often load may exceed available resources)…LOLP is typically expressed in units of "numbers of times per year" that the system demand could not be served.

[4] Testimony of Steven Sim, page 9, line 10 through page 10, line 5.

If these two analytical approaches constitute FPL's "IRP process" the Commission should absolutely *not* rely upon the results of this analysis, i.e., the choice between FGPP and natural gas generation. Even taken together, these approaches give no information about the appropriate mix of resources types (baseload, intermediate, peaking) that represents the least cost mix of resources or the value of delaying resource additions. For example, it's possible that FPL simply looked at its load and resources projection which "has been driven by the Summer reserve margin criterion,"[5] saw that it needed capacity to meet its summer reserve margin requirement and chose baseload capacity even though that capacity may not operate in the winter months (because it may not be needed).

Q. What would constitute appropriate resource planning?

A. FPL ought to present this Commission with the results of analyses that have directly compared resource choices like coal, gas, renewables and demand-side management.

Q. Do you have any additional issues you would like to raise with this Commission?

A. Yes. FPL's need for new capacity essentially appears to be a result of the 20% reserve margin requirement; a requirement that is much higher than other jurisdictions I am familiar with. To demonstrate the result of having a 20% reserve margin, I've recreated Exhibit SRS-4 for the summer months as Table 2.

[5] Testimony of Steven Sim, page 10, lines 7-8.

Table 2. Projection of FPL's 2007-2015 Capacity Needs: 15% Reserve

August of the Year	Projections of FPL Unit Capability (MW)	Projections of Firm Purchases (MW)	Projections of Total Capacity (MW)	Peak Load Forecast (MW)	Summer DSM Forecast (MW)	Forecast of Firm Peak (MW)	Forecast of Summer Reserves (MW)	Forecast of Summer Reserve Margins w/o Additions (%)	MW Needed to Meet 15% Reserve Margin
2007	22,123	2,993	25,116	22,259	1,768	20,491	4,625	22.6%	(1551)
2008	22,150	2,993	25,143	22,770	1,908	20,862	4,281	20.5%	(1152)
2009	23,370	2,511	25,881	23,435	2,034	21,401	4,480	20.9%	(1270)
2010	24,589	2,107	26,696	24,003	2,146	21,857	4,839	22.1%	(1560)
2011	24,589	2,062	26,651	24,612	2,264	22,348	4,303	19.3%	(951)
2012	24,589	1,906	26,495	25,115	2,388	22,727	3,768	16.6%	(359)
2013	24,589	1,906	26,495	25,590	2,516	23,074	3,421	14.8%	40
2014	24,589	1,906	26,495	26,100	2,651	23,449	3,046	13.0%	471
2015	24,589	1,906	26,495	26,772	2,790	23,982	2,513	10.5%	1084

If FPL had a 15% reserve margin it would need just 40 MW of new capacity in 2013.

Reserve margins are mechanisms to address resource adequacy concerns. My understanding is that FPL operates under both a LOLP standard of 0.1 days per year as well as a 20% reserve margin requirement. If the 20% reserve margin is not necessary in order to maintain the LOLP standard of 0.1 days per year, that is, if a 15% reserve margin[6] could guarantee the same LOLP standard, then FPL customers are paying additional money for capacity that brings little in the way of reliability benefits. In the case of this particular project, they are paying about $5.7 *billion*[7] extra. I would strongly encourage this Commission to open a docket to examine whether peninsular Florida's reserve margin requirement ought to be revised downward before granting an affirmative need determination for FGPP.

6 I chose 15% as the example reserve margin since I understand that prior to 1999, that was the Commission ordered minimum reserve margin.

7 FGPP Need Study, page 37.

Q. What is your ultimate recommendation to this Commission?

A. I recommend that the Commission deny FPL's need request. FPL has failed to demonstrate that FGPP is the least cost, least risk addition to its system and the Commission should revisit the 20% reserve margin requirement before approving new capacity at a cost of $5.7 billion.

FPL's analyses in support of FGPP do not comprehensively consider potential CO_2 prices and do not evaluate a full range of technically feasible alternatives. FPL's analyses do not even show that FGPP would be less expensive than building and operating new gas facilities.

Q. Does this complete your testimony?

A. Yes.

BY MR. GROSS:

Q. Mr. Schlissel, do you have a summary of your testimony?

A. Yes, I do.

Q. Would you go ahead and present that.

A. Good afternoon. Thank you for accommodating me to be able to go home tonight, I hope.

I'm a senior consultant at Synapse Energy Economics. Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission, and distribution system planning and reliability, global climate change, portfolio management, and integrated resource planning among our fields of expertise. Synapse's clients have included the U.S. Department of Justice, the Environmental Protection Agency, state regulatory commissions and their staffs, state environmental agencies, utilities, state consumer advocates, state attorneys general, and environmental organizations.

I personally have more than 33 years of experience working as an expert on energy resource planning and reliability issues. My work has included evaluations of the need for and economics of new generating facilities. I would note in a number of projects, my work has supported the acquisition of new peaking or base load capacity by utilities or independent power plant producers -- power plant owners, excuse me. My findings on resource planning issues have been accepted, in whole or in part, by regulatory commissions in a number of states, including Arizona, Texas, Indiana, Arkansas, New Mexico, Maine, and North Carolina.

Synapse was asked by our clients in this case to evaluate FPL's proposed Glades Park Units 1 and 2 based on the information provided in FPL's petition and supporting testimony. We also reviewed other publicly available information, such as FPL's ten-year plans and the regional reliability documents prepared by the Florida Regional Coordinating Council.

Unfortunately, the very abbreviated schedule in this proceeding did not permit us the time to do what we typically do before we file testimony in cases like this, which is to conduct discovery and prepare independent economic analyses comparing the proposed project to other technically and economically feasible alternatives.

The issue I addressed in my direct testimony was the potential for federal regulation of greenhouse gas emissions and the impact that that regulation would likely have on the relative economics of the Glades project. My findings on this issue were as follows:

First, it is prudent to expect that a policy to address climate change will be implemented in the U.S. in a way that should be of concern to utilities building new coal plants. The question is not whether the U.S. will develop a national policy addressing climate change, but when and how. Of course, there are important details to be worked out, but there will be regulation of greenhouse gases, and the potential costs related to that regulation should be considered by utilities and commissions in resource planning decisions.

Second, if the Glades Power project is built, it is not reasonable to expect that carbon regulation is an issue that could be reasonably dealt with in the future once the timing and the stringency of the federal regulations are known. At a minimum, it will be expensive to back-fit carbon capture and sequestration equipment and capability when and if it becomes commercially cost-effective.

A number of state commissions require utilities to reflect CO_2 emission allowance prices in their resource planning. FPL is to be commended for reflecting CO_2 prices in its planning studies. However, the range of possible CO_2 allowance prices that FPL has considered in its studies of the Glades project is too narrow, and the high end of the range of CO_2 prices considered by FPL in its analysis is too low.

In the spring of 2006, Synapse developed a set of projected CO_2 emission allowance prices that we believe utilities and other companies should use in their planning. These CO_2 price forecasts are comparable to other forecasts we have seen. Our forecasts were based on analyses of the proposals that were then being discussed in Congress up to roughly a year ago. These are price forecasts presented in Figure 1 on page 21 of my corrected direct testimony. And I would note -- I guess the companies can use that in their cross. That is our forecast. It's not all -- the background squares and triangles, I'm sure counsel for the company will discuss it. That's not ours, but the lines are ours.

Since May of 2006, a number of new bills have been submitted in Congress that propose significantly larger reductions in CO_2 emissions by the middle of this century than were proposed in any of the measures that we considered when we developed our price forecasts. It is reasonable to believe that these new bills with their larger reductions will lead to even higher CO_2 emission allowance prices than those that we forecast last year. Thus, our CO_2 price forecasts should now be considered very conservative.

At a projected 92 percent capacity factor, the Glades project will emit more than 14-1/2 million tons of CO_2 each year for what can be expected to be a 60-year operating life. The additional costs that FPL's ratepayers may have to pay for these 14 million tons of annual CO_2 emissions could range from roughly 120 to more than $400 million each year based on our price forecasts.

My supplemental direct testimony then addressed several other critical issues. First, fuel diversity -- I agree with the company. Fuel diversity is certainly an important and desirable objective. However, principles of least cost, least risk planning should compel FPL to justify the Glades project on an economic basis. I would ask the Commission to very carefully consider whether building a 1,980-megawatt coal plant is an appropriate hedge against natural gas prices if the economics do not otherwise justify the building of the plant. Additional demand-side management and conservation efforts and the building of renewable technologies also provide fuel diversity, perhaps at a lower cost.

Second, FPL considered the economics of only a very limited range of base load fossil options in its need study. In fact, it focuses mainly on a plan with coal versus a plan without coal, that is, a plan that has natural gas. I am testifying here today that you should require FPL to build a new combined cycle natural gas plant in place of its proposed Glades project. Having said that, it's clear that FPL's own economic studies do not justify the building of the Glades project.

FPL examined the coal and non-coal plans in 16 scenarios, which looked at four separate CO_2 price or environmental compliance cases and four separate fuel price forecasts. The results of FPL's analysis through these scenarios are shown in Table 1 on page 2 of my corrected supplemental testimony. The first four scenarios examined by FPL I believe can be discounted, because they assumed there would be no CO_2 costs because, I guess, there would be no federal action on greenhouse gases. As the evidence about the threat posed by global climate change mounts daily, and as I believe FPL would agree, this is not a reasonable assumption.

The second set of four scenarios examined by FPL in its need study --

CHAIRMAN EDGAR: Ms. Schlissel, I'm sorry. I'm going to have to interrupt. In the interest of time, we are way over the five minutes allowed for summary. So I'm going to need you to conclude your summary so we can turn it over to cross.

THE WITNESS: Okay. If I'm out of time, I guess I'm concluded. Okay.

CHAIRMAN EDGAR: Okay. Thank you.

Okay. Mr. Beck, do you have questions?

MR. BECK: Yes. Thank you, Madam Chairman.

CROSS-EXAMINATION

BY MR. BECK:

Q. Good afternoon, Mr. Schlissel.

A. Good afternoon.

Q. Mr. Schlissel, I would like to ask you a few questions about your forecasts for carbon allowance taxes.

A. Yes, sir.

Q. Exhibit 3 to your direct testimony.

A. Yes.

Q. Could you turn to page 52 of 62 of that exhibit?

A. Yes.

Q. At page 52 of your Exhibit 3, there's a table which shows three different forecasts for carbon dioxide allowances. Do you see that?

A. Yes.

Q. You have a low case, a mid case, and a high case; is that right?

A. Yes.

Q. And at various places in your testimony, you also have charts or line graphs showing those, for example, on the previous page.

A. Yes.

Q. And as I understand it, the graphs simply connect the points that would be shown from your table on page 52; is that correct?

A. That's correct. We just did the forecast for the three years, 2010, 2020, and 2030, and then the lines -- well, if you'll look in the company's chart over there, you'll see the lines just connect the points, in your language.

Q. Okay. Let me ask you about your low case. Could you explain the basis for your low case scenario for carbon taxes?

A. The basis for our low case is essentially that there would -- the allowance forecast would begin in 2010 at a zero price, that there would be no allowance price in 2010, and that it would increase rather slowly over time as the political will to act increased and the evidence mounted. It was based on several studies that essentially examined a proposal to increase the carbon inten -- to regulate carbon intensity. Carbon intensity means the pounds or tons of carbon emitted per megawatt-hour of generation, or actually I've seen it also in terms of percentage of gross domestic product.

The proposal to regulate carbon intensity and require reductions in carbon intensity also has a safety valve, which means that if the price of an allowance gets above 8 or $9, that's where it would stop. The safety valve would come into effect.

Q. Maybe I'm not clear. How did you develop those particular numbers for your low case, and then I want to contrast that with the mid case and the high case. What forms the basis for those specific recommendations or forecasts?

A. Well, we spent a lot of time -- and by we, I meant there was a team of us, eight of us, roughly, at Synapse who developed the forecast. We looked at five or six studies, and they're listed in the upper left-hand box of that graph. If you look on page 52 of 63 of my Exhibit DAS-3, you'll see there are 10 different studies or 10 different alternatives that we looked at.

And the basis for the low forecast again was that we didn't think that this allows for the fact that there would not be immediate action on CO_2 prices, and that essentially the action that would be taken by Congress to set up a program would focus on reducing carbon intensity with some form of safety valve in the short term.

Q. Okay. How did you develop the high case? What is the basis for that?

A. The high case was based on our view of the midpoint of the various -- you'll see there are roughly eight different -- eight or nine studies that had predicted carbon prices, carbon allowance prices for 2010. And for our high case, we just said the midpoint would be $10 per ton. Our reason for selecting $10 per ton was that we believed that a higher number in the short term would create economic dislocations or fear of economic dislocations that would discourage Congress from setting a higher price for 2010.

If you look on my Figure 6.3, which is different than the company's chart, you'll see that by the time we got to 2020, we predicted that the high price would be roughly $40 per ton, which I believe was take from an MIT study of the original McCain-Lieberman bill, Senate Bill 139. And thereafter, we believe that technology, technological improvements would lead to

Congress -- I'm sorry, would lead to decreases in allowance prices over time, less of an increase in carbon allowance prices over time.

Q. Do you see any of your three forecasts being more likely than the others?

A. Well, I think it will -- our guess is that it will probably be somewhere in the middle. We have not assigned probabilities to the forecasts. It's likely to be somewhere in the middle, perhaps our mid forecast or lower. But the whole point of doing a range of forecasts is because of the great uncertainty. You need to look at a range of possible forecasts, because nobody can predict the future, certainly not with regards to carbon allowance prices.

Q. Could you turn in your supplemental direct testimony to your Figure 2, which is on page 8 of your supplemental.

A. Yes.

Q. And basically, I want to compare your forecasts to those provided by Florida Power & Light. How does your low and medium forecast compare to Florida Power & Light's various forecasts, if you could describe that?

A. FPL's forecasts, there -- this is a confusing chart because of the various lines. It's better in color.

Q. Okay. Well, let me ask this. FPL's medium forecast, that's above your low forecast, is it not?

A. That's correct.

Q. And it's also beneath your medium forecast; is that right?

A. That's correct.

MR. BECK: Mr. Schlissel, thank you. That's all I have.

CHAIRMAN EDGAR: Mr. Krasowski, do you have questions for this witness?

MR. KRASOWSKI: We don't have any questions at this time. Thank you.

CHAIRMAN EDGAR: Okay. Thank you. Mr. Litchfield.

MR. LITCHFIELD: Thank you, Madam Chairman. I have a few questions.

CROSS-EXAMINATION

BY MR. LITCHFIELD:

Q. Good afternoon, Mr. Schlissel.

A. Good afternoon. I need my distance glasses.

Q. Yes. We were much closer in Iowa.

A. No. Actually, I think we were about the same distance, but the witness chair was elevated, which gave a closer sense of intimacy.

Q. Glad you felt that way.

All right. I would like you first to turn to Figure 1 on page 21 of your direct testimony and tell me if that is the figure reflected on the white board up behind you to your right.

A. No, it isn't.

Q. It's not?

A. No. There are some -- I'm sorry. I apologize. It is.

Q. Okay. Now, I want you to focus -- Commissioners, do you have the color version of the exhibit in front of you?

CHAIRMAN EDGAR: No. We have black and white. You have black and white?

MR. LITCHFIELD: I would like to distribute color versions if that would be --

CHAIRMAN EDGAR: We all have black and while. We'll be glad to have color.

MR. LITCHFIELD: I would definitely prefer you to have color.

I apologize for the delay. I think it actually will speed things up if you're looking at a color version. I just assumed that you would have it.

BY MR. LITCHFIELD:

Q. Okay. Mr. Schlissel, you have that in front of you. Would you focus for the purpose of my next few questions strictly on the solid blue line and the two dashed lines indicated at Synapse's high, mid, and low cases, respectively? Do you see those?

A. Sure.

Q. So temporarily, let's just ignore the other data points shown in different shapes and colors on this graph. Okay?

A. Okay.

Q. Now, you didn't generate these three lines through any independent modeling. That's correct, is it not?

A. We didn't do modeling of our own; that is correct. It's based on modeling of others and the various studies that are indicated by the triangles, squares, and diamond shapes.

Q. Right. And essentially, there is -- in other words, there is no model per se that underlies these three lines; correct?

A. No. Again, the model -- there are a number of models that underlie these lines. We did not calculate these three lines by means of a separate model, but our analysis is based on the modeling done by others.

Q. Right. I think you may have answered this question with Mr. Beck earlier, but you essentially connected the three points that Synapse decided represented the high, medium, and low cases respectively in each of those three years; correct?

A. What we did was, we made a high, low, and mid projection in 2010, '20, and '30. The lines merely connect each of those points.

Q. That's a yes. Thank you. That was my question. And you didn't try to predict values for each year, did you?

A. No, not at all. That would be extremely difficult and probably foolish to try to get that specific.

Q. All right. So you looked at the results of the various scenarios plotted here on this graphic from the studies that you examined, and you concluded that based on the range of data points -- that based on the range of data points, the range of likely costs in 2010 was from zero to something like below 10; correct?

A. Yes.

Q. And so you plotted zero as your low, 10 as your high, and you split the difference to get your mid case of 5; correct.

A. I believe that's correct, yes.

Q. And just to confirm, these lines weren't generated as a result of any type of regression analysis; correct?

A. That's correct. The lines merely connect the three points in each -- you know, the low connects the low forecast in 2010 and the low in 2020 and the low in 2030.

Q. Okay. Now I would like you to focus on the colored and shaped data points reflected on Figure 1. Can you do that?

A. Yes.

Q. Now, so that we understand what these various shapes and colors represent, I'm going to ask you a few clarifying questions similar to those that I asked you at your deposition. Okay?

A. Okay.

Q. Now, data points of the same color represent certain CO_2 cost scenarios based on the same proposal or piece of draft legislation; correct?

A. Correct.

Q. So, for example, each blue point is based on a particular scenario from a study that was undertaken to attempt to model potential CO_2 costs of a proposal reflected in Senate Bill 139; correct?

A. Yes. That was the original McCain-Lieberman proposal.

Q. And we see that indicated in the legend here at the top left of Figure 1; right?

A. Yes.

Q. All right. And then each violet data point reflects a scenario from a study undertaken to model potential CO_2 costs of a proposal reflected in Senate Bill 843; correct?

A. Yes. I believe that was Senator Carper's Clean Air Act, Clean Air Power Act, something like that.

Q. All right. And that's also indicated in the legend in the top left of the graphic; correct?

A. Yes.

Q. Now, when you have two or more dots of the same color, they are intended to represent two or more scenarios selected by Synapse from among multiple scenarios run by the folks that actually did run the model; correct?

A. That's correct. The MIT study that you see listed of Senate Bill 139, the original McCain-Lieberman, I believe they had 12 to 14 different scenarios that modeled different credits, percentage of credits that were allowed and things like that.

Q. And Tellus and EPA and MIT and the other entities indicated in this legend at the top left of the graph, they're the ones who did the model, they're the ones who chose the assumptions, gathered the data, interpreted the bill being evaluated, and actually ran the model; correct?

A. Yes, I think that's fair to say.

Q. Then they published their output; right?

A. Yes.

Q. All right. Synapse then took studies, read them, eliminated certain scenarios based on whether or not Synapse believed they most closely approximated the bill, and then reflected the results of that review on Figure 1; correct?

A. That's partially true. I thought we discussed this during my deposition, but I was ill that day, and if I missed it, I apologize. We also wanted to have a wide range of possible scenarios so that we didn't miss any --

Q. Well, I'm pretty sure you were at your depo.

A. Excuse me?

Q. I think you were at your depo, weren't you?

A. No, no. I may have missed saying that. It wasn't only that we picked the scenarios that were closest to the bill. It was also that we wanted to have a range of possible scenarios to look at, given the great uncertainty inherent in evaluating these costs.

Q. You just wanted to supplement the answer that you gave me at your deposition. Is that what I'm understanding?

A. No. What I said was I don't remember whether I said that at my deposition. If I didn't, I apologize, because I was ill that day. So I'm not supplementing. I believe I'm repeating it, but if I'm not, I apologize.

Q. Well, I'll take a minute and just look back at your depo. Do you have a copy of your depo in front of you?

A. No.

Q. Let me get you one if your counsel doesn't have one.

A. Thank you.

Q. Let me ask, were there any particular scenarios that you felt -- that you dismissed, that Synapse dismissed and therefore did not reflect on the graph here, any that you recall?

A. No. As I said, the MIT study had a number of scenarios. Some of the others had advanced technology scenarios that were compared to advanced technology reference cases. We didn't include those. We stayed with the base reference case in each study and then looked at the sensitivity scenarios and how emissions changed and the emission allowance prices under those sensitivity cases compared to the base case scenarios. But beyond that, there were a lot of studies, a lot of scenarios we examined as a group. If you have any in particular you want to talk about, I would be happy to try to. I brought the studies with me in case you wanted to.

Q. Actually, I think we may look at some of those studies. There isn't anything in your testimony, however, is there, to indicate how Synapse made a selection, if you will, of the various studies or the various scenarios that were modeled by these entities reflected or identified on Figure 1, is there?

A. In my testimony, no. I don't recall whether it's mentioned in Exhibit DAS-3, but --

Q. All right. Let's look back at page 21 of your direct testimony.

A. Okay.

Q. Now, recall that we established earlier that data points of the same color represent certain CO_2 cost scenarios based on the same proposal or piece of draft legislation; agreed?

A. Yes, sir.

Q. Okay. So we looked at the blue points and the violet points and agreed that those originated from studies conducted relative to Senate Bill 139 and Senate Bill 843 respectively; agreed?

A. That's correct.

Q. All right. Will you turn to page 10 of your testimony and look at Table 1?

A. Okay.

Q. All right. You see starting on page 10, there's Table 1, Summary of Mandatory Emissions Targets in Proposals Discussed in Congress?

A. Yes.

Q. And it carries over onto page 11?

A. Yes.

Q. Now, there are 17 bills or proposals identified in Table 1. Would you agree with me?

A. I haven't added them, but I trust your math.

Q. Subject to check?

A. I probably won't even check it. I trust it.

Q. Fair enough. Now, of the total 17, the first 11 are not current at all, are they?

A. That's correct. They -- I guess the term is "expired," when that particular Congress left office.

Q. Now, if one wanted to limit oneself to consideration of only current proposals, then one could literally or figuratively draw a line through everything up to the Feinstein-Carper Senate 317 bill on page 11; correct?

A. That is correct. And in fact, we are in the process of attempting to do that re-evaluation within the next month or two to look at what are the likely CO_2 emission allowance prices given the new and what we believe more stringent legislation being considered in Congress.

Q. Okay. But none of that is in the record, and none of that is in your prefiled testimony. You agree with me on that; right?

A. Well, the bills are in the record to the extent they're mentioned on this table, and I believe I mentioned in the testimony that in fact, the numbers in our forecasts may be conservative because of the new bills in Congress. But beyond that, there's nothing in the record.

Q. And there's no analysis to support that contention either, is there?

A. Well, the contention that we're going to re-evaluate it?

Q. No, the contention that current bills may result in higher CO_2 forecasts. There's no analysis in your testimony to support that particular contention, is there?

A. That's correct. The evidence is, I believe, in the table you and I are looking at that the bills are more stringent. But in fact, we will have to see as the analyses of the bills come out what impact or what projected emission allowance prices they have.

Q. So in fact, looking back to Figure 1 on page 21, and this is the colorful exhibit that we've been looking at, all of the data points in fact on this graph represent selected scenarios from studies of bills that are not currently before Congress. Would you agree?

A. No. I can agree with a lot of what you say, but they're not all selective. Some of the studies were only one scenario, so we used that scenario.

Q. They were -- I'm sorry.

A. They were bills that were before Congress. Some of them were bills before Congress at the time we prepared this analysis. But other than that, I would agree with your statement.

Q. So with that qualification, you otherwise agree?

A. Yes.

Q. Take a look at the line representing your high case. And that's the dashed line -- and it's difficult in this lighting, but -- it looks a little violet to me.

A. I wouldn't dare to suggest what color it is.

Q. Fair enough. It's the highest dashed line on the graph.

A. Yes, the top dashed line, why don't we call it.

Q. Okay. If I were to count all the data points that are either above that line or just touch it, would you agree with me that that number is 11?

A. Yes. I actually think there's probably -- the number is probably nine, but that's okay.

Q. Okay, nine.

Now, would you agree that if we looked at the highest blue and green figures or data points reflected on this graph that those all represent bills that were before Congress in 2003? In other words, I'm looking back at your Table 1, the McCain-Lieberman, Senate 139 and Senate Amendment 2028. All of the green and the blue data points on this graph relate back to studies based on those two proposals in 2003; agreed?

A. Yes, if I could, with a caveat that the McCain-Lieberman bill in the form of 2028 was resubmitted in 2005 and was alive again in 2006. So that bill, I think exactly the same provisions, was alive in 2005 and '6.

Q. In 2005 and '6 with no changes?

A. I might be wrong, but I think that it certainly had the same emission caps in 2028. The change was from -- Senate Bill 139 had a two-step process that from 2010 to 2015, emission limits would be set at the year 2000 emissions, and that in 2016 and going forward, it would be at 1990 year emission levels. That bill was then amended to become 2028 by eliminating the second half of the -- the second step so that it only contained the 2000 year level cap, emissions cap.

Q. Okay. But regardless of whether the amended version, 2028, whether it was or was not changed through the '04-05 time period, which you're not certain today, but regardless of that fact, you would agree with me that that bill is not the one that was modeled by these particular entities and not the results of which are reflected in your testimony and on this Figure 1? You agree with me on that?

A. No. The question -- I'm sorry. Maybe it's because I didn't have my glasses on, but the question contained too many clauses in there.

Q. I'm rephrase it.

A. I don't know what I'm agreeing to and disagreeing with.

Q. Fair enough. I'm rephrase it, Mr. Schlissel. What I really wanted to confirm is that what you've modeled -- no, excuse me. Let me rephrase that. What you reflect on Figure 1 in the form of the blue and green data points relate to scenarios from studies that were based upon proposals before Congress in 2003?

A. And the answer is yes, with the caveat that the same emission limits that were in the bill, 2028, were also before Congress in 2005 and '6.

Q. And is it your testimony that nothing changed between 2003 and 2005?

A. Actually, the only thing that -- no, I'm not sure. I know that certainly with regards to the relevant matters, the bill didn't change. There was a change in regard to credits to nuclear power plants at some point between Senate Bill 139 to 2028, but I don't recall exactly the year when that change occurred.

Q. And what was the name of that bill?

A. It still -- it was all McCain-Lieberman.

Q. I know, but it obviously had a new number, right, if it existed past 2003?

A. Yes. I'm sorry. I don't recall the number of it, but I know Senator Lieberman reintroduced it, I believe, sometime in 2005 or '6.

Q. Okay. And I guess this will be simple, because whatever the number of that bill is, it's not reflected on Figure 1, is it?

A. That's correct, but its provisions may be, because they were similar to 2028.

Q. May be.

A. No. My testimony is, I can't remember all of the details of the bill, the reintroduced bill, but in the germane issue of emission allowance limits, it was the same.

Q. All right. Well, assume with me for the sake of discussion that the Commission did not want to base its impression of future CO_2 scenarios on a model that comes from proposals in Congress that date back as far as 2003. Can you make that assumption for my next question?

A. Okay.

Q. Okay. Would Figure 1 simply look the same as it does today with the exception of all of the blue and green data points being eliminated?

MR. GROSS: I'm going to object to the form of that question. I agree that hypothetical -- I'm sorry. It is proper to ask hypothetical questions of experts, but there must be some either existing basis in the record, or it's a proffer that in good nature will be put into the record. So you would have to put into the record the assumption -- if it's not already in the record, it would have to be put into the record before this hearing is over that the Commission would not want to consider that material. Otherwise, I think it's an improper -- it assumes a fact that's not in evidence or will never be in evidence.

MR. LITCHFIELD: But I haven't proposed to offer an exhibit yet. I've simply asked the witness -- I'm sorry, Madam Chairman. I've simply asked the witness --

CHAIRMAN EDGAR: Actually, Mr. Litchfield, I've forgotten the question.

MR. LITCHFIELD: I've simply asked the witness as a hypothetical to assume for me that if the Commission chose to ignore data based on 2003 bills, in other words, looking for something a little more contemporary, what would Figure 1 look like. It's his figure, and I think he's in a position to answer it. He has already indicated to me that Senate Bill 139 and Senate Amended Bill 2028 date to 2003, and that the blue and the green points relate back to those bills. So it's a conceptual question, and I think it's a fair one.

CHAIRMAN EDGAR: I agree with the statement that it's a conceptual question. And with that, I'll allow, but I will ask you to restate it to the witness.

BY MR. LITCHFIELD:

Q. Mr. Schlissel, if the Commission were not inclined to base its impression of future CO_2 prices on scenarios modeled on the basis of proposals or bills that were before Congress in 2003, then would Figure 1 redone with that constraint look as it does, with the exception of eliminating the blue and the green dots?

A. Well, I mean, conceptually, of course it would. If you took out some of the bills, you would remove some of the dots. But if we're going to do that conceptually, this would look different if we didn't include the dots related to the EIA cap and trade and the National Commission on Energy Policy proposal, which was never introduced in Congress. So, yes, of course you can take out bills and take out dots or triangles or whatever.

Q. And I'm distributing, Mr. Schlissel, an exhibit that I would like you to take a look at.

A. Thank you.

MR. LITCHFIELD: And, Madam Chairman, I would ask to have it marked, and I believe the next number is 161. Is that right?

CHAIRMAN EDGAR: Hold on. Let me get there.

MR. LITCHFIELD: 163?

CHAIRMAN EDGAR: I am at 163. But before we do that, let me ask Ms. Brubaker. The prior document in color that you passed out that we had in black and white but is in color, I realize that it's already in the record before us in black and white, so that we do not need to mark or re-enter, or should we, since it is slightly different than what we have?

MS. BRUBAKER: It is slightly different.

Perhaps in an abundance of caution, it might be appropriate to identify it.

CHAIRMAN EDGAR: Okay. Mr. Litchfield, does that work for you?

MR. LITCHFIELD: That we mark it for identification?

CHAIRMAN EDGAR: Yes.

MR. LITCHFIELD: I'm fine with that. So it would be 163, and that is Figure 1 from Mr. Schlissel's direct testimony on page 21.

CHAIRMAN EDGAR: Yes.

MR. LITCHFIELD: And 164 would be Mr. Schlissel's Figure 1 on page 21 absent blue and green data points.

CHAIRMAN EDGAR: Okay.

(Exhibits 163 and 164 marked for identification.)

BY MR. LITCHFIELD:

Q. Mr. Schlissel, would you agree that this is in fact how Figure 1 would look if the blue and the green data points were eliminated?

A. I trust that you've left the other points in the right spot. Sure.

Q. Now, you indicated earlier that the McCain-Lieberman bill was amended, and that became SA

2028; correct?

A. Yes.

Q. And that reflects the -- the green dots reflect 2028; correct?

A. Yes.

Q. Or green data points?

A. Yes.

Q. And the blue reflect the earlier version of the McCain-Lieberman bill; correct?

A. Yes.

Q. Is it fair to say, based on the blue and green data points -- and I'm referring back to your Figure 1 on page 21, Exhibit 163 for hearing purposes, that in fact the amended version of the McCain-Lieberman bill apparently resulted in lower CO_2 costs than the original proposed bill? Would you agree with that?

A. Right. As I explained before, instead of a two-step process, it was a one-step process. But just so the record is clear, the new McCain-Lieberman bill is back to the two-step process, and then it has further reductions after 2020. So if we're going to take out the blue and green dots because the data is too old, you need to insert new dots, because the new current bill that's before Congress, as I said, includes the same two steps as the original Senate 139, and then has further reductions in subsequent years, if you look on Table 1 on page -- the portion on page 11 of my testimony that you and I discussed before.

Q. Now, the McCain-Lieberman bill as it's currently proposed, though, includes 100 percent more offsets than the prior version, i.e., SA 2028. Would you agree with me on that?

A. Do you have evidence? I don't recall. I mean, sitting here today, I don't recall every provision of every bill. If you've got some evidence of it, I will look at it.

Q. We'll be happy to put that in front of you. But it's not your recollection that the offsets for compliance were increased from 15 to 30 percent? That's not your recollection?

A. No. Actually, the original bill had a declining set of offsets. The offsets declined over time. Again, I don't recall every provision of every bill before Congress on this subject. I'm sorry.

MR. LITCHFIELD: Madam Chairman, I can pull it out. In the interest of time, if we could take administrative notice of the current McCain-Lieberman bill, and I can get you the bill number for that.

CHAIRMAN EDGAR: Ms. Brubaker?

MS. BRUBAKER: Give me just one moment. The only concern I have as far as official recognition is that I believe it's enacted acts of Congress. I don't know that a draft would qualify as that. Certainly we have no objection to entering the draft as an exhibit or what have you, but I don't think it would be probably appropriate for official recognition, but I'll be happy to pull those rules and look at them real briefly.

MR. LITCHFIELD: In fact, we would be fine with submitting it as a late-filed exhibit, if that's --

CHAIRMAN EDGAR: Late-filed exhibit?

MR. LITCHFIELD: -- if that's acceptable to --

CHAIRMAN EDGAR: Filed as a late-filed exhibit. Mr. Gross, does that --

MR. GROSS: I'm sorry. What is it that you're proposing to file?

MR. LITCHFIELD: It's S 280. It's Senate Bill 280.

CHAIRMAN EDGAR: Okay. So, Mr. Gross, the matter that we have before us is a request to file a late-filed exhibit, which would be a copy of a filed, not passed, but filed congressional legislation. And we're going to allow Ms. Brubaker to look at the rule. Mr. Gross. Mr. Gross, make sure your mike is on, if you would, for me, please. Thank you.

MR. GROSS: Thank you. You know, it's

self-evident that testimony is filed at a certain point in time and hearings are started and concluded at a certain point in time, and things change.

CHAIRMAN EDGAR: Including the order of witnesses.

MR. GROSS: Yes. And if this late-filed exhibit is to go into evidence, then I think we should have an opportunity to present late-filed exhibits that also bring this matter up to date as of today. There may be other bills that also are in effect today that were not in effect on the day that this testimony was filed. And if we're going to update everything right up to today, then we think in the interest of fairness -- if this witness feels that there should be other bills or similarly relevant evidence that would be relevant to this table, then we should have the right to file those exhibits as late-filed exhibits as well.

MR. LITCHFIELD: Madam Chairman, in principle, I don't think we're opposed to having all of the current bills included as late-filed exhibits, but I think -- it sounds like it will be easier just to have the bill printed, which we're doing right now, and we can put it in front of Mr. Schlissel and have him corroborate the fact that offsets had increased from 15 to 30 percent.

CHAIRMAN EDGAR: Ms. Brubaker.

MS. BRUBAKER: Madam Chairman, having looked at the relevant portions from Chapter 90, there does not appear to be any provision that would allow us to take official recognition of the draft. However, again, as a late-filed draft, staff certainly has no objection.

CHAIRMAN EDGAR: Okay. Mr. Gross, do you understand the alternative suggestion that Mr. Litchfield has offered, and if so, do you have a comment?

MR. GROSS: Okay. Would you repeat it again, Mr. Litchfield?

MR. LITCHFIELD: We'll simply get the bill and put it in front of Mr. Schlissel.

MR. GROSS: Well, I still think there's a fairness issue here. If you're permitted to do this, then we should be able to introduce late-filed bills well -- bills as late-filed exhibits as well.

MR. LITCHFIELD: That's not what I'm proposing at this point, Madam Chairman. I think it's becoming much complicated than it needs to be.

CHAIRMAN EDGAR: My understanding, Mr. Litchfield, is that you have withdrawn your request for a late-filed exhibit; is that correct?

MR. LITCHFIELD: Yes.

CHAIRMAN EDGAR: Okay.

BY MR. LITCHFIELD:

Q. Would you agree with me, Mr. Schlissel, that offsets affect the cost of CO_2 compliance to a great degree? Would you agree with that?

A. They certainly will affect it. I don't know what you mean by great. They certainly affect the cost of the emission allowances for the years that the offsets are in effect. If you look at McCain-Lieberman Senate Bill 280 on page 11, you'll see that the first step is a 2004 level in 2012, which is a higher emission cap than the original McCain-Lieberman bill had in the year -- had for 2010 to 2015. So there were certainly changes between the original bill and the bill in Congress now that will affect --

MR. LITCHFIELD: Madam Chairman, this is completely unresponsive to my question.

CHAIRMAN EDGAR: Are we all keeping track of the time? I know I am. Let's proceed.

BY MR. LITCHFIELD:

Q. Mr. Schlissel, I simply asked you whether offsets contributed greatly to the ultimate compliance cost of any particular CO_2 regime, and I think you agreed with me. If that's not correct, then --

A. No. I said that I would agree they would affect the price. I don't know what you mean by greatly, so I can't agree with a vague term like "greatly." It certainly affects the price of the emissions allowance for the period during which the offsets are in effect.

Q. Are offsets a less expensive way to achieve compliance?

A. Generally they are believed to be a lesser cost alternative, yes.

Q. Therefore, it's expected that offsets would be fully utilized by any company that was subject to CO_2 regulation. Would you agree with that?

A. When you say is expected, it's reasonable to expect that companies will consider using offsets. It may be for some companies, they don't need to, they don't want to for some reason. But you would expect them to use the lower cost alternative, sure.

Q. Okay. All right. What do the black triangles mean around the yellow triangles on Figure 1? This is Exhibit 164.

A. It's a second -- there were two scenarios from the EIA's review of the NCEP proposal, I believe.

Q. Do you recall what the difference in the scenario was?

A. No. I mean, I have the documents with me. We could go through them.

Q. Would you be willing to accept subject to check that the black outline around the triangle in each of the two cases there represents a scenario with no safety valve?

A. Correct. And the triangles without the black -- I'm sorry. The yellow triangles without the black border represents the safety valve. Yes, that's correct.

Q. Okay. And a safety valve is what?

A. A safety valve is the price at which -- basically, a cap on the emission allowance price.

Q. Okay. And a safety valve is something that Congress might implement in the event that they felt that above a certain economic impact, there would be too much detriment to the economy, and they might therefore institute a safety valve price. Is that your understanding?

A. Yes. This one was for the National Commission on Energy Policy proposal.

Q. And if there is no safety valve, then prices would be free to rise?

A. Supply and demand, yes.

Q. Now, look at the orange triangles on either Exhibit 163 or 164. We're still on Figure 1. Do you see those on the far right in the year 2030?

A. Yes.

Q. Those are both safety valve prices, aren't they?

A. I believe so.

Q. So a safety valve price effectively is a ceiling price. It's not an expected price. It's a ceiling price; correct?

A. Correct.

Q. Do you have the EIA analysis of Senate 139 with you?

A. Yes. The June 2003?

Q. I believe that's correct, but I'll confirm that momentarily. Yes.

A. Okay.

Q. And I'll ask Ms. Cona to distribute copies. And I'm looking at page 10 of that document. Do you have that?

MR. LITCHFIELD: And, Madam Chairman, I would like to have this marked. I'm just distributing the cover page and then page number 10 in the interest of efficiency.

CHAIRMAN EDGAR: Okay. So we are at 165. Will you label for me?

MR. LITCHFIELD: Analysis of Senate 139, June 2003, page 10.

CHAIRMAN EDGAR: Thank you.

MR. LITCHFIELD: I guess I should note -- Madam Chairman, I'm sorry. It's EIA analysis of Senate 139 dated June 2003, page 10.

(Exhibit 165 marked for identification.)

BY MR. LITCHFIELD:

Q. Okay. On page 10, you see Figure S-1, the graph?

A. I'm sorry. Page 10?

Q. Page 10.

A. I must be in the wrong document, because my page 10 analysis of S. 139 has a table.

Q. Yes. I want you to look at that table. Ms. Cona will hand you a copy of Exhibit 165. Let's make sure we're looking at the same thing.

A. Okay. Okay. I have the -- your exhibit.

Q. Okay. And you see in the year 2025 a price of $60 in terms of the allowance price?

A. Yes.

Q. And you see an offset price of $15; correct?

A. Correct.

Q. So that would suggest that in fact the offset price is one-quarter the price of compliance under this scenario; correct?

A. That's true, to the extent that the offsets are available.

Q. Now, this particular document served as the basis for which color dots on Figure 1 on either Exhibit 163 or 4? It's the blue, is it not?

A. I believe, yes.

Q. Okay. So where on Figure 1 in blue for the year 2025 do you reflect an offset price of $15?

A. Where do we reflect it? In the year 2025, our high price is not up at the level of the EIA study. The blue triangle is -- what is it? Ten, $12, something like that, higher than our high price. So we didn't put the offset price on there, but we reflected our high price is lower than the EIA estimated price, in part because we believed that there would be offsets and that they would have an impact on the allowance price.

Q. Okay. We're focusing then on this blue triangle at the height of the graph. In fact, it's the highest data point in the entire graphic; correct?

A. Correct.

Q. And it appears to me that it reflects maybe not 60, but 58 or 59. Is that not your read?

A. Sure. Now, the difference could be it's different year dollars.

Q. Well, is it your representation that this data point does reflect companies taking full advantage of offsets at $15 per metric ton --

A. No.

Q. -- in lieu of paying $60 per metric ton?

A. I'm sorry if you didn't understand what I tried to explain. My point is, our high forecast is not at this high point. If we did not reflect offsets and technological changes, then we would have put our point for 2025 on this point. However, we don't think that allowances will reach the point that the EIA calculated in its analysis of Senate Bill 139, and that in part reflects our belief, the point you're trying to raise about the impact of the use of offsets.

Q. But it's not reflected in the data point, that's my question, the offset price of $15. And under this version of the bill, offsets were available to be used for purposes of compliance of up to 15 percent of one's compliance; is that not right?

A. No. In phase 1, they were allowed to be 15 percent. In phase 2, they were limited to 10 percent.

Q. Okay. Ten percent then. But really, my question is just -- the value or the discount associated with compliance attributable to the availability of offsets is not reflected in this data point that we've been discussing, this blue data point at the top of the graph?

A. I'm sorry. I don't understand your point. It's reflected in our analysis, in our forecast, which is what's important. I would have to look at the work papers to see whether in fact it's reflected in that specific data point. But I don't --

Q. So you don't know today?

A. Well, I would like to look at the --

Q. Mr. Schlissel, it's either a yes, a no, or an "I don't know." I'll accept either one.

A. No, it's not -- right. I guess -- well, give me a second here to think about this.

I don't recall. I would have to look at the work papers.

MR. LITCHFIELD: Okay. I think we have Senate 280. I think I just have one copy, though, unfortunately, so permission to approach the witness. I'm really just looking for him to confirm that offsets under S 280 are now 30 percent of one's compliance obligation as compared to 15 percent.

CHAIRMAN EDGAR: You may. If you would, just make sure that if you are speaking to the witness or to us that we can hear you in a microphone for the record.

BY MR. LITCHFIELD:

Q. Okay. This is Senate 280, and I'm asking the witness to refer to section 144, subsection (a), alternative means of compliance. And if you would just read that section there?

A. "Beginning with calendar year 2012, a covered entity may satisfy up to 30 percent of its total allowance emission requirement under section 121 by," and then it goes on. Yes.

Q. So offsets are eligible for up to 30 percent of compliance under S 280?

A. It would be under the bill as it's currently drafted, or -- what's the date of the draft you've got, just so I'm clear?

Q. January 12, 2007.

A. That's -- I mean, I don't remember the day it was introduced. I believe it was in February, but I have no reason to doubt that the provision is in there.

Q. Mr. Schlissel, how much of the nation's electricity today is generated by coal?

A. I don't recall the number. Sorry.

Q. Do you know roughly the percentage?

A. I don't know. I would guess maybe 20, 30 percent. I'm just guessing. I haven't looked at the numbers in years.

Q. What if it were 50 percent or roughly 50 percent? Is that a number you've heard before?

A. Again, I haven't looked at that number in years. If you want to give me a number -- well, I don't know how I would check it, but --

Q. We might be able to get one in front of you, but for purposes of the next few questions, assume for me that it's approximately 50 percent. Do you have any sense as to how many megawatts that would represent?

A. What the capacity, the generating capacity in the U.S. is today? No.

Q. Okay.

A. I remember a lot of esoteric facts, but I don't remember that one.

Q. So then I take it you would not be able to suggest to me that if all of that coal generation went away and was replaced by natural gas-fired generation, by how much this country's demand for natural gas would rise? You're not in a position to estimate that number for me, I take it?

A. No. Just a caveat. No one, especially myself, is sitting here proposing that all of the generation from coal go away immediately.

Q. Just new coal?

A. Immediately. The plan is to reduce CO_2 emissions by 2050 to the 450 to 550 parts per million levels that are generally believed by scientific consensus to be required to stabilize temperature increases in the atmosphere.

Q. Okay. I want to pursue that for a moment, but I've got a couple of other questions I just want to close out on that last topic.

A. Okay.

Q. I just want to make sure that you're also not in a position then to tell me whether the country would have either (a) the reserves or (b) the infrastructural capacity to deliver the amount of volume of natural gas required in order to displace all existing coal-fired generation. You're not able to tell me that today; right?

A. Well, I'm not proposing that it happen. No one credible that I know is proposing that would happen. So the answer is yes, I can't give you an analysis of what I don't think is a credible alternative.

Q. If the national policy objective is to reduce carbon emissions and policymakers also conclude that we simply cannot displace all of our coal-fired generation, then they're going to have to make certain policy decisions, correct, with respect to the type of coal that they would favor versus the type of coal that they would disfavor; agreed?

A. No, you're throwing in there if they decide that they can displace all coal-fired generation.

Again, I don't know that that's anybody's goal or --

Q. No, no. I'm sorry. If they cannot. If the decision, if the policy decision is made that we cannot afford to displace all of our coal-fired generation with natural gas, but we do want to reduce CO_2 emissions, then what I'm asking you is, does Congress or the policymakers at that point have to decide the type of coal that they would favor versus the type of the coal that they would disfavor?

A. I'm sorry. Maybe it's the lateness of the day. I don't understand the question. It seems to me that the policy decision is not only replace coal with natural gas. As I know FPL is aware, there are plans to build some new nuclear power plants. There are plans hopefully for energy efficiency, renewable technologies. So there's a whole portfolio of approaches to reduce carbon emissions. I have no doubt that coal will be a part of the U.S. generating capacity for the remainder of this century. The question is reducing CO_2 emissions to 80 percent or so of 1990 levels.

Q. Well, would you agree that if coal needs to be, as you say, a part of this country's generating portfolio at the same time that the country wishes to undertake a reduction in CO_2 emissions, that it should incent cleaner burning coal plants and disincent dirtier burning coal plants? Would you agree with that?

A. By dirtier, you mean what?

Q. Higher emissions.

A. Excuse me?

Q. Higher emissions.

A. Again, if I'm interpreting you right, I agree with you. If I'm not, then I would disagree with you.

Q. Well, you've got to tell me how you interpret me then.

A. Well, no. Unfortunately, when you're talking about disincenting cleaner and dirtier burning coal plants, I mean, if you're talking about incenting new coal plants to replace older coal plants, it's a complicated question. If you're talking about incenting more efficient plants in the future over less efficient new plants, sure, everybody would want there to be more efficient new plants than less efficient new plants.

Q. So you would not advocate a regulatory system that rewards cleaner burning coal even if they are new facilities over higher emissions coal plants that are existing facilities. Is that what I'm hearing?

A. No, not at all.

Q. So what would you propose?

A. But it's a complicated question, because if you're going to replace -- let's suppose you were going to build a 1,000-megawatt coal plant and retire 1,000 megawatts of 50-year-old coal plants. Well, in the short term, that's a great idea. I think it benefits.

The problem is, the new plant you're going to put on line is going to be generating 14-1/2 million tons or so of CO_2 for 60 years, whereas the older plants that are burning -- or that are higher -- dirtier plants, to use your term, may have higher emissions in the short term, but they'll be retired in 10, 15, 20 years. So --

Q. And replaced with what?

A. -- it's a complicated question.

Q. And replaced with what?

A. I'm sorry?

Q. And replaced with what? When those older, higher-emitting plants are retired, they're replaced with what under your scenario?

A. Under my scenario? I don't have a scenario. I've looked at the retirement of plants on a case-by-case basis. There may be instances where coal does make sense. There may be instances where natural gas makes sense. There may be instances where the company or companies or a state will seek to do energy efficiency or more renewables. There may be instances where some nuclear power plants get built. It's a complicated situation.

Q. Would you agree that the U.S. has for years been attempting to move to less dependence on foreign sources of energy?

A. No. I believe that there has been a stated political goal, but I don't think there's very much effort in reducing our dependence on foreign oil. And certainly there's no -- I've seen no evidence -- in fact, I've seen evidence in the other direction about increasing our dependence on foreign natural gas and foreign coal.

Q. Do you support, however, decreasing our dependence on foreign fossil fuels as an important policy objective? Is that someone that you endorse? Irrespective of your views on whether we're actually accomplishing that, is that a principle or an objective that you endorse?

A. Would I like to see that for security reasons? Yes, I would like to see a reduction -- certainly on foreign oil is number one. On foreign natural gas, I don't know. On foreign uranium, I'm concerned about the fact that so much of our uranium in the future will -- it seems that so much of our uranium will be coming from the former Soviet Union. That gives me concern for security reasons. With regards to coal, I don't know.

A lot of the coal comes from Colombia. You never can tell what's going to happen with the country down there with the drug trade, et cetera. So I am concerned about that.

Q. But this country has 200-plus years of domestic reserves available, does it not, of coal?

A. Yes. But there's also a problem called global warming and global climate change that has to be addressed.

Q. Would you agree that supercritical pulverized coal plants have been identified as clean-burning coal units under the Energy Policy Act of 2005?

A. Yes, they have been.

Q. And ultra-supercritical pulverized coal plants are more efficient than supercritical pulverized coal; would you agree with that?

A. That's what's being claimed for them, yes. I've not seen the statistics from the Japanese -- I'm sorry. Yes, Japanese and German plants to confirm that, but it has been proposed that they would have higher -- I'm sorry, lower burn rates, and therefore be more efficient -- lower heat rates, excuse me, and be more efficient.

MR. LITCHFIELD: Madam Chair, I have more to do, but what I would propose -- I would propose, in the interest of time, seeing where we are, to enter Mr. Schlissel's deposition and have him dismissed.

CHAIRMAN EDGAR: Mr. Gross, we can all stay. We are trying to work with the schedule parameters that you had laid out. Mr. Litchfield, I appreciate your cooperation on that point as well. I think we have two alternatives, and the first is that we can stay.

Mr. Litchfield, if you were to continue with cross, do you have a rough estimate as to how much longer?

MR. LITCHFIELD: My guess -- well, my guess is about 20 minutes, 30 minutes.

CHAIRMAN EDGAR: Okay. And are there questions from staff for this witness?

MS. BRUBAKER: Staff has none.

CHAIRMAN EDGAR: Commissioners, do you have questions for this witness, depending on where we head?

Mr. Gross, I think we have two alternatives, as I see it. I'm open to a third if you're aware of a third. The two that I see are that we can continue on and allow Mr. Litchfield to continue with his cross of this witness, and if the Commissioners have questions, give them that opportunity as well, which I'm going to guesstimate 30 to 45 minutes, being hopefully generous, which would require, from the information you gave us, for the witness, my apologies, to change some of his scheduling, or as Mr. Litchfield has suggested, to enter the sworn deposition testimony in lieu of additional cross. And it is your witness, and so I will look to you for a recommendation.

Yes, we will take a moment for you to consult with your witness. And then, Ms. Brubaker, I'll look to you.

(Off the record briefly.)

CHAIRMAN EDGAR: Mr. Gross.

MR. GROSS: I would still prefer to finish the cross. If we can't do it today, give us an opportunity to see if we can under any circumstances get Mr. Schlissel back here.

CHAIRMAN EDGAR: Okay. So that sounds like a third option, and I did give you an opportunity to provide a third option, which would be -- and, Mr. Litchfield, I will look to you for comment, but to stop cross at this point, with the opportunity, Mr. Litchfield, for you to pick up where you were next week, Wednesday or Thursday.

MS. REIMER: Can we excuse him?

CHAIRMAN EDGAR: Not yet. I'm sorry. Mr. Litchfield.

MR. LITCHFIELD: I'm happy to do that. I

would note, however, that I think it was pretty clearly, pretty firmly indicated that this witness was not available, and now we're hearing that, oh, well, maybe we can make him available.

I would point out -- and I think we're entitled under the Rules of Civil Procedure to enter the deposition of a party for any purpose permitted by the Florida Evidence Code. And I'm reading from Rule 1.330, the Rules of Civil Procedure. That, of course, would mean that Mr. Gross would be free to object as to relevance or some other reasonable and legitimate objection under the Rules of Evidence as to what portions might not come in. But short of that, I think we are entitled to put it in, irrespective of whether Mr. Schlissel is available next week or not.

So I think I would propose that, and then we could decide whether we needed to pick up with him next week.

CHAIRMAN EDGAR: I guess that's what I get when I give the opportunity for additional options. I am also, Mr. Litchfield, trying to -- again, I appreciate everybody's cooperation, but also, my preference would be for the Commissioners to have the opportunity to ask questions as well, which obviously if we end now -- and we were holding off, realizing that you had expressed a need for cross, and we wanted to work with you.

So, Ms. Brubaker.

MS. BRUBAKER: Well, if I may, just my personal opinion, I think that there had been a great deal of accommodation by the Commission of the difficulties in scheduling. I don't know for certain what difficulties there are in rescheduling a flight.

I do have some concerns about whether the deposition can be entered over objection. I think the relevant rules make it clear that there is an opportunity to object for various reasons for admissibility.

CHAIRMAN EDGAR: All right. Then my request is that we allow Mr. Schlissel to leave us at this point in time, with the understanding, Mr. Gross, that we will be seeing him on Wednesday or Thursday next week and, Mr. Litchfield, that we will give you latitude in extending your cross at that point in time.

MR. LITCHFIELD: Thank you, Madam Chairman.

CHAIRMAN EDGAR: Mr. Gross.

MR. GROSS: Madam Chair, first I just want to thank you for accommodating us and just let you know that I appreciate that.

CHAIRMAN EDGAR: You are welcome.

Mr. Schlissel, thank you. You are excused.

THE WITNESS: I greatly appreciate it.

CHAIRMAN EDGAR: However, we look forward to seeing you next week. We will welcome you back to Tallahassee at that point.

THE WITNESS: That's great. Is Thursday okay?

CHAIRMAN EDGAR: If you will work with your counsel, and our staff will work that out, and you can head out.

THE WITNESS: Okay. Thank you very much.

CHAIRMAN EDGAR: Thank you. Okay. 4:40. You had one more witness, I think, that you wanted to try to get in today, did you not, Mr. Litchfield?

MR. LITCHFIELD: We did. We had Mr. Brandt that we had been hopeful of getting on and off. Of course, that depends on the kind of cross-examination, but it would be wonderful if we could accomplish that.

CHAIRMAN EDGAR: Okay. Mr. Gross, and I'm looking for Mr. Beck. Mr. Beck, can you do your cross of witness -- I'm sorry, Brandt this afternoon?

MR. BECK: I have no questions.

CHAIRMAN EDGAR: You can. You have no questions.

Okay. Mr. Gross, are you prepared to work with us in cross for this witness? We can give you a few moments if you need to.

MR. GROSS: Yes. It might just take one moment.

CHAIRMAN EDGAR: Okay. Let's take five in order to shuffle papers.

MR. KRASOWSKI: Madam Chair.

CHAIRMAN EDGAR: Mr. Krasowski, yes, sir.

MR. KRASOWSKI: We had quite a bit of questions for Mr. Brandt, and his testimony and his issues are pretty much the basis of our interests or hopes to explain opportunities other than the coal plant. So I don't know how long it will actually take us, but I would hate to be pushing you past what you want to do with the rest of your time for later. So I don't know -- I think Mr. Brandt is a local person, and --

CHAIRMAN EDGAR: I appreciate you letting me know that, and what I'm going to do is, as I said, take five minutes. During that five minutes, I'm going to ask our staff to get with Mr. Litchfield, with Mr. Gross, and with you. And I'm also going to juggle my schedule here for the next few minutes, and then we'll come back and see where we are. Okay?

MR. KRASOWSKI: Okay.

MR. LITCHFIELD: And, Madam Chairman, with respect to the cross-examination exhibits, did you want to handle those now, at least the ones that we've identified so far?

CHAIRMAN EDGAR: My thinking is that if we're going to have the witness back, that we can take them up then.

MS. BRUBAKER: I think that would be best.

MR. LITCHFIELD: That's fine. I just --

CHAIRMAN EDGAR: Does that work for the record and for -- okay.

MR. LITCHFIELD: It works for me. I just didn't want to lose track.

CHAIRMAN EDGAR: I appreciate that. Okay.

(Short recess.)

(Transcript continues in sequence with Volume 5.)

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 458 through 650 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 18th day of April, 2007.

Mary Allen Neel

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