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 7

Pages 862 through 1085

PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN LISA POLAK EDGAR COMMISSIONER MATTHEW M. CARTER, II COMMISSIONER KATRINA J. McMURRIAN
DATE:	Wednesday, April 25, 2007
TIME:	Commenced at 9:30 a.m. Recessed at 6:10 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

P R O C E E D I N G S

(Transcript follows in sequence from Volume 6.)

CHAIRMAN EDGAR: We will go back on the record and get started again after the lunch break. First of all, I apologize for my tardiness and being a little longer than I had said. It's just another one of those days where we've got a lot going on.

I believe that right when we took lunch break, we were going to have questions from Commissioners and questions from staff. So to our witness, thank you. Commissioner McMurrian.

Thereupon,

DAVID N. HICKS

continues his sworn testimony from Volume 6 as follows:

COMMISSIONER McMURRIAN: Thank you, Chairman.

Mr. Hicks, I guess this question came to mind when we were looking at Exhibit 175, that was marked as 175, and it was the cost of electricity comparison. And I just wanted to ask, does it cost more to add carbon capture -- I guess generally, does it cost more to add carbon capture to pulverized coal plants than it does to add carbon capture to IGCC plants?

THE WITNESS: I would say in the time frame that we would be looking at carbon capture as an option to meet climate change requirements, it would be more expensive to add to IGCC rather than to PC. PC, you can -- you leave a space in the design, and then you can just add that equipment to it. IGCC is different in the sense that a number of pieces of equipment have to be either reengineered or replaced. So in the time frame, in the relevant time frame, my contention would be that IGCC is more expensive to add carbon capture equipment to.

COMMISSIONER McMURRIAN: Okay. That clears that up, because I think at some point you were talking about how costs converge over time, and I wasn't really clear what you meant there. Are you saying that with technology improvements and things like that, that over time the costs may not differ as much or --

THE WITNESS: Yes. With all the emphasis now on R&D for new carbon capture equipment, the general consensus is that the cost of carbon capture for both technologies are going to get lower and converge with each other.

COMMISSIONER McMURRIAN: Okay. Thank you. And then the other questions I had were actually just to help me understand some of the terms on some of the items marked -- I believe it was 166 through 168, and there were several different charts regarding efficiency and heat rate and such. I guess specifically looking at Number 168, which was the Black & Veatch exhibit -- do you have that?

THE WITNESS: Uh-huh.

COMMISSIONER McMURRIAN: Just so that I can understand better how to compare these percentages to the percentage efficiency that you've given us, which I believe was 38.8 percent --

THE WITNESS: Average degraded 38.8, yes. That's over the life of the plant.

COMMISSIONER TEW: With respect to the column that says "Net Plant Efficiency," can you tell me what that term means and how that compares to the efficiency that you've put forward?

THE WITNESS: Yes. During the lunch break, I reviewed this document. And I actually attended this conference where Mr. Ott presented this document. This was in fact the last time I talked to Mr. Ott. This was a CSX coal forum that was held in Welaka, which is a resort they have in Palatka. And what he's referring to here in terms of net plant efficiencies is general efficiencies looking at what they call ISO conditions, which is like 59 degrees Fahrenheit, new and clean type of conditions versus the conditions that I represented when I talked about the FPL Glades Power Park plant.

The other thing I would note is, what Mr. Ott was trying to present with this document is not Black & Veatch's current view of what subcritical, supercritical, and ultra-supercritical conditions would be, but what their view of the world, of the state of the industry would be towards the latter part of the next decade, given that certain advances in metals were achieved. There have been some setbacks in terms of those metal advances, but this really represents their view of the world towards the latter part of the -- or the second half of the next decade.

What they actually view as ultra-supercritical in the current time frame and during the time that the FPL Glades Power Park will come online is actually in the Clean Coal Technology Study, which they assisted us on. There's a table in there in which they discuss -- it's Table 3-1, where they discuss notable worldwide ultra-supercritical plants. The ultra-supercritical plants that are in there are consistent with what we're proposing at FPL Glades Power Park.

COMMISSIONER McMURRIAN: So is there a table within the Clean Coal Technology -- and that's attached to your testimony, isn't it?

THE WITNESS: Yes. There's a table inside the Clean Coal Technology Study that actually has steam temperatures, pressures, and reheat temperatures consistent with what Black & Veatch's view of ultra-supercritical technology is in the state of the art now and in the foreseeable future.

COMMISSIONER McMURRIAN: Can you tell me where that is in the --

THE WITNESS: It's page 3-1.

MR. ANDERSON: Commissioner, we're having a copy of that walked around to everybody.

COMMISSIONER McMURRIAN: Okay. Thank you. I'll look at that later.

I wanted to ask some other questions about some of the terms in several of these documents. The PSIG term, can you tell me what that means?

THE WITNESS: That's pounds per square inch. And I don't recall what the G means, but it's a measure in terms of pounds per square inch.

COMMISSIONER McMURRIAN: And those terms should mean the same thing throughout different documents, as far as your understanding would be?

THE WITNESS: Yes. As far as my understanding, yes.

COMMISSIONER McMURRIAN: And then with the Black & Veatch document, that far right column where it says "Net Plant Heat Rate, HHV," can you --

THE WITNESS: That's higher heating value.

COMMISSIONER McMURRIAN: Excuse me?

THE WITNESS: That's higher -- what they call higher heating value.

COMMISSIONER McMURRIAN: And do those terms -- whenever HHV is referenced on other documents, do those mean typically the same thing?

THE WITNESS: Yes, it does.

COMMISSIONER McMURRIAN: Okay. Chairman, I believe that was all. Thank you for pointing me to the other documents.

THE WITNESS: Thank you.

CHAIRMAN EDGAR: Questions from staff?

MS. FLEMING: Thank you, Chairman.

CROSS-EXAMINATION

BY MS. FLEMING:

Q. Good afternoon, Mr. Hicks.

A. Good afternoon.

Q. Just a few questions. Does the Glades Power Park meet the requirements to be considered clean coal technology under the Energy Policy Act of 2005?

A. Yes, it does. And we will be applying for clean coal tax credits this year. The application deadline is June 30th.

As a point of reference, the Duke Cliffside plant, which is a pulverized coal plant, was awarded clean coal tax credits last year. The Duke Cliffside plant is not as advanced technology as FPL Glades Power Park, nor does it include the same emissions control equipment that the Glades Power Park does. And that --

Q. Has FPL -- excuse me.

A. And that project was awarded tax credits by the DOE last year.

Q. Has FPL formally met with the Department of Energy regarding their eligibility for the Glades Power Park?

A. We have not formally met with them yet. We've had a number of informal telephone discussions. Our analysis, though, shows that this plant will meet the requirements, and we will be scheduling a meeting with them in advance of our application submittal.

Q. But at this time, FPL does not know if the coal plant will actually qualify for tax credit; correct?

A. We do not have a final determination at this time.

Q. And even if FPL files for tax credit, it's not guaranteed that it will be approved; correct?

A. That is correct.

Q. Did FPL include the value of these potential tax credits in the estimate of cost of the Glades Power Plant?

A. No, we didn't, because we don't have those tax credits in hand.

Q. If FPL does qualify for and obtain these tax credits, would these tax credits or funding be used to reduce the final cost of the coal project for the benefit of the customers?

A. Yes, they would.

Q. Okay. Mr. Hicks, I would like you to turn to what's marked as staff Exhibits 155 and 156. They're the yellow and blue packets in front of you, and I've actually tabbed with a yellow sticky tab the relevant pages that I need you to look at.

Specifically in Exhibit 156, it's pages 12 and 21, or for ease of reference, that information is just consolidated on one page on page 3 of Exhibit 155, which may be easier to look at so you have your side by side comparisons.

A. Yes. I have them in front of me.

Q. Okay. Specifically, I'm going to be looking at the emission rates and just talk about the comparison of emission rates between the ultra-supercritical power plant and IGCC. Looking at the exhibit, on page 3 of Exhibit 155, which is the yellow cover --

A. I'm looking at that.

Q. The CO_2 emissions rates seem to be the same for a coal plant and an IGCC; correct?

A. For the purposes of the modeling, we used the same emissions rates in pounds per MMBtu. But because the IGCC plant has a higher heat rate, it uses more MMBtus of fuel to produce electricity. The overall emissions rate on a pounds per megawatt-hour basis for the IGCC plant will be higher, but the rate in terms of pounds per MMBtu of fuel is the same.

Q. And as far as -- let me have you look up at SO_2. The emissions rates are identical for the coal plant as well as an IGCC; correct?

A. In this diagram, yes, they are; correct. That's correct.

Q. Can you explain why that is?

A. The SO_2 rates -- I would have to -- actually, I have to defer to Mr. Sim, but my assumption would be the SO_2 rate, what it reflects is a 80/20 mix for the pulverized coal plant, 80 percent coal, 20 percent petroleum coke, and a 50-50 mix between petroleum coke and coal for the IGCC plant. The higher the petroleum coke, the higher the emissions rate for SO_2 for all technologies.

Q. Now, as for the mercury emission rate, looking at this chart, it appears that the mercury emissions rate are higher for an IGCC than a coal plant; correct?

A. For this diagram, yes. We used the requested mercury emissions rate for the AEP 600-megawatt IGCC plants located in Ohio and West Virginia as the proxy for the mercury emissions rate for the IGCC plant.

Q. But typically, wouldn't a coal plant have a higher mercury emissions rate than an IGCC?

A. No, particularly when you look at the FPL Glades Power Park, because the FPL Glades Power Park includes four emissions control technologies, the SCR, the baghouse, the wet flue gas desulfurization, and the wet ESP. Those are not specific -- each one of those is not specifically designed to reduce mercury, but they have co-benefits, in that they reduce mercury. Our anticipation is that those four devices will lead to about a 90 percent removal rate, which is state of the art, given the sensitivity of measurement devices.

But because FPL was committed to going above and beyond in terms of mercury emissions rate, we've also included activated carbon injection. With activated carbon injection, we anticipate mercury removal rates as high as 94-1/2 to 95 percent, which exceeds that for IGCC.

Q. And what is typically the mercury removal rate for IGCC?

A. For most technologies -- well, there's not a typical number. As you can see, with the AEP, they asked for a mercury removal rate or mercury emissions rate double. The Orlando Utilities plant has a mercury emissions rate slightly higher than FGPP. Other facilities have mercury removal rates at or slightly below. Once again, it's driven in part by fuel type, the type of fuel used.

Q. In addition to just looking at the emission rate, is it also important to look at the total amount of pollution that's emitted from a power plant on an annual basis?

A. I'm going to defer that question to Mr. Kosky, because he's our expert on emissions control, and he can provide you a much more detailed answer on that question.

Q. And earlier you discussed the extent to which the Glades plant is designed to be capture-ready. Do you recall that?

A. Yes, I do.

Q. Has there been any analysis done to date which addresses the sequestration of carbon that could be accomplished at the FGPP site?

A. There has been no formal analysis to date, but

I would note that that entire area has deep saline aquifer geology, which is consistent with one of the primary opportunities for carbon capture and sequestration, or for carbon sequestration.

Q. For any combustion technology that's out there, what is currently available to sequester CO_2 once it's captured?

A. A process called MEA is one process that's available. But given the current state of R&D, expectations are that by well in advance of this plant, MEA will be obsolete, and something akin to the chilled ammonia or another type of process will emerge as the most cost-effective process in terms of carbon capture.

Once again, I would -- earlier I discussed this concept of the horse and cart concept between carbon capture and sequestration. The horse in this instance is carbon sequestration, so it's going to take longer to really resolve the sequestration issues than it is the carbon issues for all technologies across the United States. So by the time sequestration becomes a reality, you'll have commercial carbon capture systems at a much lower cost and much more efficient than what you see today.

Q. And if you know, has FPL considered constructing or participating in a joint ownership of an

IGCC unit to determine whether this technology may be used in a future application for its system?

A. We are currently -- I'm also project manager for an IGCC refueling study at our Martin site that would involve refueling of one of the gas-fired combined cycles to produce -- rather than oil and natural gas, to burn syngas and natural gas. And we've been in that process with a joint venture partner, which is a major vendor of IGCC equipment, since about last August. I can report that the results to date are not promising, both in terms of cost and in terms of emissions. We still hold hope that that may pan out, but right now the numbers just don't look very good.

In addition to that, we've had a lot of discussions with the vendor with regard to carbon capture, and we've gained a lot of knowledge through the process. That's where we gained the understanding that in terms of IGCC, the vendors are really about in the same place they are -- with regard to carbon capture as they are with PC. They're just leaving a space in the design for the carbon capture.

MS. FLEMING: Thank you. We have no further questions.

CHAIRMAN EDGAR: Redirect?

MR. ANDERSON: Yes, please. Chairman Edgar, I believe this would be Exhibit 175.

CHAIRMAN EDGAR: I am on 176.

MR. ANDERSON: 176. I'm sorry. Thank you.

CHAIRMAN EDGAR: That's okay.

(Exhibit 176 marked for identification.)

REDIRECT EXAMINATION

BY MR. ANDERSON:

Q. Mr. Hicks, you were asked some questions earlier today about the definition used by FPL for ultra-supercritical pulverized coal technology. You have before you Exhibit 176. Could you tell us what this is and how it relates to the definition?

A. It's a document entitled "Clean Coal Technology." It's put out by the United States Department of Energy. And on page 2 of the two pages in the document, it provides the DOE definition of ultra-supercritical. Under the heading "Materials Development for Ultra-supercritical Boilers," it states, quote, "As part of its effort to develop cleaner, more efficient power generating systems to meet future energy needs, the United States Department of Energy, DOE, Office of Fossil Energy is collaborating on important work to develop high-temperature, corrosion-resistant alloys for use in ultra-supercritical steam cycles. Steam cycles with operating pressures exceeding 3,600 pounds per square inch and main superheat steam temperatures approaching 1,100 degrees Fahrenheit are considered ultra-supercritical," end quote.

Q. Is this the definition that FPL has used and referred to in its clean coal study?

A. Yes, it is.

Q. Do you have before you Exhibit 168, which was Mr. Ott's presentation you were asked about earlier?

A. Yes, I do.

Q. If you would please flip through to the third page of what we have here, first, looking at the page numbers, does this look like the entire presentation that you saw when you attended this?

A. No, it's not. It's selected slides from that presentation.

Q. Okay. But just as to the slides we do have here, look at page 3 titled "Thermal Generation Technology Spectrum." Do you see that?

A. Yes, I do.

Q. You were asked some questions this morning directed at the bottom of this page about advanced supercritical and ultra-supercritical and about temperatures and pressures, you know, inferring that perhaps FPL's ultra-supercritical project is not that. Would you comment on what this document is and what it actually shows?

A. This document is -- Mr. Ott in presenting this overall presentation was trying to give a viewpoint of the current state and future state of PC technology. And the purpose of this slide was to demonstrate that even PC technology is an evolving technology. And what this represents is not the current view of the definitions of supercritical, subcritical, and ultra-supercritical, or the view in the time frame that FGPP would be constructed, but an advanced view based upon significant improvements in exotic metals or metals that are used in the combustion process. So those metals, particularly with regard to what's defined here as advanced supercritical and ultra-supercritical, those metals are not available. They are not commercial. They are not available, and so those plants cannot be built and are not on the drawing board for any entities to be built.

Q. So that's just sort of a future view then?

A. It is a future view; that's correct.

Q. Okay.

A. It does not represent the current view.

(Exhibit 177 marked for identification.)

BY MR. ANDERSON:

Q. We've previously walked around to everyone in the room a document which I think would now be 177. This is the document called "Clean Coal Technology Selection Study, Final Report, January 2007," a three-page document. The second pages have 3-1 and 3-2 at the bottom. Mr. Hicks, do you have a copy of 177?

A. Yes, I do.

Q. Tell us what this document shows in relation to Black & Veatch's and FPL's expression of what ultra-supercritical pulverized coal technology means in the current environment?

A. If you look on the top cover, it shows both the Black & Veatch logo and the FPL logo, which represents the joint view of both Black & Veatch and FPL. This table was put together by Black & Veatch and represents their view of notable worldwide ultra-supercritical plants.

Q. Are there any plants on here that compare roughly in terms of temperatures and pressures, for example, to the FGPP plant that FPL is proposing to build?

A. Yes. If you look at the bottom of page 3-1, Hitachi Naka, which is a 1,000-megawatt unit, very similar in size, it has a steam pressure of 3,675 and main steam and reheat temperatures of 1,112 degrees Fahrenheit, very close to the FPL plant, which is 3,700, 1,112, and 1,130.

On the next page, the Hranomachi plant, 3,675, 1,112, 1,112, and the Tachibanawan, which is 3,750, 1,121, and 1,135, all those are within very close proximity to the FPL proposed plant.

Q. So those are all actual ultra-supercritical projects?

A. They are actual operating ultra-supercritical projects, yes.

Q. They're not proposed?

A. They're not proposed.

Q. They're in commercial operation?

A. They are in commercial operation, yes.

Q. Looking, please, at what Mr. Guest labeled as Exhibit 166, NETL Materials Research Program, do you have that?

A. Yes, I do.

Q. Could you page through that for me -- it does not have page numbers on it, but counting the cover as page 1, 2, 3, 4, 5, 6, 7, Pulverized Coal Efficiency, this is a slide that Mr. Guest showed you; is that right?

A. Yes.

Q. Would you please comment whether this correctly shows the current industry understanding of subcritical, supercritical, and ultra-supercritical?

A. No, it doesn't. It represents -- once again, the same as the Black & Veatch, it represents a view of the future of these technologies. And particularly the higher temperatures and pressures are dependent upon significant advances in materials and metals that have not been realized to date and have actually been pushed back somewhat. If you look, I believe it's one, two, three further pages into it, it actually has a time line for those ultra-supercritical materials, and it doesn't really show those materials becoming commercial until around the year 2015.

One should note this is a 2003 presentation, and since this presentation has come out, the advancement in these very exotic metals and materials has been slowed somewhat. In fact, it's delayed several plants in Europe to the second half of the next decade because of the delays in those materials.

Q. So this is another future view?

A. It's another future view.

Q. And the future is coming a little slower than we had expected?

A. The future is coming a little slower than once expected, yes.

Q. Looking at what was marked as Exhibit 167, "Final Report, Environmental Footprints," et cetera -- do you have that in front of you?

A. Yes.

Q. There's a page 1-1. Design Basis, the first paragraph talks about the modeled plants include, and then counsel referred you to various supercritical steam definitions of things. Does this set of definitions represent the current industry understanding of ultra-supercritical?

A. No, it does not. Once again, particularly the steam pressures are significantly higher than the current view of what ultra-supercritical is. This is just -- it appears to be just a modeling exercise more than a representation of the current state of the art of ultra-supercritical technology, particularly with regard to steam pressures.

Q. This is by the EPA?

A. Yes, it is.

Q. They're not in the business of actually building plants; right?

A. No, they're not.

Q. Okay. Please look at document 175, which is the cost of electricity comparison which was submitted by Richard Furman, RCF-7, and you were asked some questions about it. Do you have that?

A. Yes, I do.

Q. Were you present at Mr. Furman's deposition when he talked about this exhibit?

A. Yes, I was.

Q. Could you tell us about the relevance and sources of the information and whether it's the kind of thing that a commission or company would rely on in making a $5.7 billion decision?

A. The sources of this document -- the sources of these numbers are not consistent with the construction of power plants in South Florida. These represent representative Midwest plants, smaller sizes, and the basis for these numbers is also in question.

Q. Do they include FGPP's capital costs?

A. No, they do not.

Q. FGPP's O&M expense?

A. No, they do not.

Q. Non-fuel costs?

A. No, they do not.

Q. Florida Power & Light company's projected fuel costs?

A. No, they do not.

Q. Or consideration of CO_2 sensitivities?

A. No, they do not.

Q. None of those things are on RCF-7?

A. None of those things.

Q. And you were asked some questions about the cost and status of CO_2 capture technology in reference to this?

A. Yes.

Q. Would you please comment on the date of this presentation in reference to the development of information concerning CO_2 capture?

A. The date of this is preliminary results, September 2006. Just in the intervening time between September 2006 and today, there has been significant advancements in CO_2 capture.

Q. Mr. Krasowski asked you about why you selected Glades County for construction of FGPP. Are there reasons you would construct a coal plant in Glades County, but not a gas-fired combined cycled plant?

A. Yes. The Glades County site is a coal-fired power plant site. It has characteristics that are consistent with a coal plant site. One characteristic is, unlike a gas plant, the rule of thumb for a coal plant is one and a half acres per each megawatt of generation. So given this is a roughly 2,000-megawatt facilities, we were looking for 3,000 acres or more, mainly because of the loop track for the rail line, the fuel storage, and the by-product handling.

Also, this site was advantaged from a coal perspective because it has a rail line that abuts the site, and that rail line connects to two major networks. If we were to build a gas-fired power plant site, we would not build it at this site. It is not advantaged as far as a gas-fired power plant site is concerned. It is advantaged as a coal plant site and does provide significant economic benefits to the community.

Q. Please look briefly at Exhibits 172, 173, and 174, which were given to you by Mr. Guest to review. One is "Operating IGCC Facilities," another is "Proposed Projects, IGCC and Polygeneration in North America," and then the third, "Proposed IGCC and Gasification Plants Ex-North America." Do you have those?

A. Yes, I do.

Q. Would you please comment on whether those documents and the information contained in them change FPL's views concerning technology selection?

A. No, they don't, because all these projects, including the corrected one from Nuon, all these projects are relatively small projects. They don't move the needle in terms of fuel diversity. To get fuel diversity in FPL's system, we need the 2,000-megawatt sizing. None of these plants meet that sizing.

In addition, I have seen this document 172 before and noticed the plant costs. And what I did is, I corrected those plant costs for 2014 dollars to get an idea of what those plant costs would look like in 2014 dollars, and each one of those plants is significantly more expensive than the FPL Glades Power Park in 2014 dollars. And I would note that the Tampa Electric plant, I corrected it for the actual costs of the plant rather than the projected costs which are listed on that line.

MR. ANDERSON: Okay. Then I'm going to pass around document 17 -- what? I'm sorry. Eight?

CHAIRMAN EDGAR: I'm on 8, 178.

MR. ANDERSON: Thank you, Chairman.

CHAIRMAN EDGAR: Will you give us a title?

MR. ANDERSON: Yes, please. "Comparative Dollars Per kW for Operating IGCC Facilities."

(Exhibit 178 marked for identification.)

BY MR. ANDERSON:

Q. Mr. Hicks, would you explain what this document is and how it relates to documents 172 through 174? You were asked some questions earlier about comparing dollars per kW for IGCC.

A. Yes. What I did is, I took on the last column plant costs, and I escalated them using historical and projected escalation rates for capital costs. Between

1994 and 2003, the blended escalation rate between labor and materials ran roughly around 3 percent. The industry, the construction industry as a whole, and the power plant industry in particular, experienced significant increases in escalation during 2004, 2005, and 2006, and those are reflected in the next three numbers. And then consensus in the industry is that -- and this is adopted by FPL, is that beyond 2007, beyond 2006, we're assuming a 4 percent escalation rate.

So the first column you see there is the years, and the second column you see is historical and projected acceleration rates for capital costs. The columns you see is where I took each one of those capital costs that's listed here, with the exception of the Polk plant, which I put into the corrected numbers, and then escalated them to 2014 dollars.

Q. So to just pick one of these numbers so we just explain it, you --

A. Let's look at Nuon (Demkolec), which is the first one.

Q. Right.

A. That has a plant cost in dollars per kW in 1994 of $2,372. I took that 2,372 and escalated it to 2014 dollars and got $8,521 per kW.

Q. So $8,521 in 2014 dollars per kilowatt, how does that compare to FGPP?

A. FGPP all in, which, by the way, in South Florida includes substantial transmission upgrades, is about $2,900 per kW in 2014 dollars.

Q. Looking across the bottom row of Exhibit 178 for year 2014 dollars, how do all the dollars per kW compare generally to FGPP?

A. All the dollars per kW generally are much higher with the exception of one plant, which is the Sarlux plant. And I would say, given the numbers for all the other plants, that something is missing there. That might be an inside, just an inside the fence number or what you call an overnight capital cost number rather than a fully loaded capital cost number.

Q. Okay. And what does this show overall if you compare costs of existing IGCC --

A. It shows that -- you know, once again, it's further evidence that the capital costs of IGCC plants are significantly greater than those for ultra-supercritical or pulverized coal plants in general.

MR. ANDERSON: That's all we have. Thank you.

CHAIRMAN EDGAR: Then we need to take up exhibits. Mr. Guest.

MR. GUEST: May I have an opportunity just to have a very short recross?

CHAIRMAN EDGAR: Based upon what?

MR. GUEST: I think this -- I want to inquire whether this exhibit was generated over lunchtime.

THE WITNESS: It was not.

MR. GUEST: Okay. That's one issue.

CHAIRMAN EDGAR: Was that the witness? Did you respond?

THE WITNESS: Yes.

CHAIRMAN EDGAR: Generally you let me respond to the --

THE WITNESS: Oh, I'm sorry. I apologize.

CHAIRMAN EDGAR: Thank you.

THE WITNESS: I apologize.

CHAIRMAN EDGAR: Although I do appreciate your cooperation in trying to answer the questions, but sometimes you have to let me think first.

THE WITNESS: Okay. I'm sorry.

CHAIRMAN EDGAR: That's all right. Mr. Guest, did you have further --

MR. GUEST: I just have a handful of --

CHAIRMAN EDGAR: But again, based upon what?

MR. GUEST: Oh, based on the new testimony, of course, nothing that I'm repeating. For example, let me -- may I give you a illustration?

CHAIRMAN EDGAR: How about if I ask another question and we go from there?

MR. GUEST: Yes.

CHAIRMAN EDGAR: Okay. Based upon information that has come up in redirect or on previous cross?

MR. GUEST: I guess redirect. I guess that's right. I'm trying to -- well, I don't have them separated fully in my mind about which one it is. The one I have in front of my, no doubt about it, it's redirect.

CHAIRMAN EDGAR: Okay. Well, then let me turn to our counsel. Mr. Harris.

MR. HARRIS: To the extent that he has questions about the redirect, it would be within your discretion to allow it. To the extent that he has questions based on other cross-examination, I do not believe that would be appropriate. I'm a little concerned that counsel indicated he hasn't decided which are based on redirect and which are based on recross, or on cross.

MR. GUEST: Well, may I just go straight to the issue, Madam Chairman? When I see cross-examination which looks to me like it's rehabilitating the witness's testimony, it doesn't feel like cross to me. And, for example, what we got on some of the cross was --

CHAIRMAN EDGAR: Mr. Guest, quite frankly, then you have the opportunity to object at the time that the question is asked, and from this point forward, let's try to do it that way. Generally I do not allow recross. However, if there is something that has come up in the redirect that you feel compelled to follow through briefly, I will allow it.

MR. GUEST: Okay. Let me just ask one or two then.

RECROSS-EXAMINATION

BY MR. GUEST:

Q. The document that was brought to you which was marked -- which is "Clean Coal Today," 177, we hadn't previously -- 176?

CHAIRMAN EDGAR: 176 is the way I have it marked.

BY MR. GUEST:

Q. 175. That's actually a newsletter from DOE; correct?

A. It says it's a newsletter about innovative technologies for coal utilization, but it includes a U.S. DOE definition in there.

Q. Right. And that's completely inconsistent with the definition provided by the National Energy Technology Laboratory?

A. No, I would not say it's inconsistent, if you could point to me where it is.

Q. Well, it's inconsistent with Exhibit Number 168?

A. Is that the one titled "NETL's Materials Research Program"?

Q. Yes.

A. No. As I indicated, these definitions are consistent with the diagram about three pages later, which indicate ultra-supercritical materials necessary to support those type of steam conditions. Without those exotic metals, you cannot achieve these type of steam conditions, and today you can't design and build with these type of steam conditions. Those exotic metals are not available.

Q. So are you saying then that the definition of what ultra-supercritical is changes with time and that these documents are referring to a definition of ultra-supercritical that doesn't even exist now and will be a definition used at some future time? Is that it?

A. Pulverized coal technology is an evolving technology, and as that technology evolves, the characterizations of what are ultra-supercritical, supercritical, and subcritical will change over time. But the current definition of ultra-supercritical, not only the DOE definition, but the consensus of the industry, is that the plant that we are proposing is a state-of-the-art ultra-supercritical plant and will bring the highest efficiency coal plant ever proposed for the United States when looked at in terms of proper temperature, pressure, and climatic conditions.

Q. And lastly, just one question. Document number -- you know, I should be more careful about marking these things. 177. This is the table by Black & Veatch. That was made as an exhibit for this case after the petition was filed; isn't that correct?

A. This was included in my direct testimony, as an appendix to my direct testimony. The Clean Coal Technology Study was appended to my direct testimony in this case.

Q. But it was made by Black & Veatch as an exhibit for this proceeding; correct?

A. No. The original document was made as a part of the Clean Coal Technology Study that Black & Veatch did in conjunction with FPL. This document is DNH-2, which is one of the exhibits to my direct testimony in this case.

Q. Dated after the petition was filed?

A. I don't know what date the petition was filed, so I can't answer that question. I can tell you this was appended to my -- this is part of a document that was appended to my direct testimony.

MR. GUEST: Thank you for your indulgence, Madam Chairman.

CHAIRMAN EDGAR: Thank you. Mr. Anderson.

MR. ANDERSON: Nothing.

CHAIRMAN EDGAR: Okay. All right. Then let's take up the exhibits. We have Exhibits 25 through 38. Seeing no objections, we will enter 25 through 38 into the record.

(Exhibits 25 through 38 admitted into the record.)

MS. BRUBAKER: Madam Chairman, if a may, just a point of clarification. We have currently identified but not entered Exhibits 162 through 165 on a prior day of hearing. That was during Mr. Schlissel's cross-examination. I recommend we do not take those up at this time, but wait until Mr. Schlissel has joined us again. And that would bring us to Exhibits 166 through 175, which Sierra has put forward, and 176 through 178, which FPL put forward on redirect.

CHAIRMAN EDGAR: Mr. Anderson, any objections to the exhibits that Mr. Guest has put forward.

MR. ANDERSON: One caveat as to Exhibit 168, which is the partial pages of the Ron Ott presentation.

We're happy to have that go in, but we've asked counsel to give us a copy of the full presentation. We would like to reserve the right to offer the balance of that presentation if we feel it should go in, if that works for people.

CHAIRMAN EDGAR: Mr. Guest.

MR. GUEST: That's the whole document rule and, of course, we agree to that.

CHAIRMAN EDGAR: That is the whole document?

MR. GUEST: What I mean to say is, there's a -- the whole document rule is that when someone puts in one document, anybody can put the rest in, and obviously, we play by those rules.

MR. ANDERSON: And because I asked counsel to provide that to me, he has agreed to produce it, as I understand, but I haven't seen it yet. If upon examination we wish to offer the whole thing, that's the only caveat. That's the only observation on any exhibit. We have no objection to the balance.

CHAIRMAN EDGAR: Okay. Thank you for the clarification. And so with that, we will enter exhibits 166 through 175.

(Exhibits 166 through 175 admitted into the record.)

CHAIRMAN EDGAR: Mr. Guest, any objections to the three exhibits that Mr. Anderson has put forward, which I have as 176, 177, and 178?

MR. GUEST: May I have a moment?

CHAIRMAN EDGAR: You may.

MR. GUEST: Just as to 178. We are endlessly puzzled by this, because -- by 178, because you may have observed my previous argument about asking for judicial recognition of the commutative property of multiplication.

CHAIRMAN EDGAR: I recall that discussion.

MR. GUEST: And I think that this is sort of the same thing, but it's a much larger set of calculations. Maybe what we should do is spot check a few of these and reserve an objection, or do you want me to spot check them now? This is kind of a tricky calculation, because it's a present value calculation, where it's -- why don't we deal with that?

MR. ANDERSON: Our suggestion would be -- first of all, let me defer to the Chair as to how you would like to proceed, but --

CHAIRMAN EDGAR: Well, actually, I was going to ask for your comment.

MR. ANDERSON: Okay. My thought would be, first, I'm confident that the figures are fine, but if counsel wants to take a look at them, we'll happily amend any specific figure. But our suggestion would be admit it into the record, subject to our agreement to make any changes indicated based upon any math error that's found.

MR. GUEST: That works for me.

CHAIRMAN EDGAR: Does that work for you?

MR. GUEST: Yes.

CHAIRMAN EDGAR: Okay. Then again, we will all work together to try to get the right result comfortably. Okay. With that, then we will enter Exhibits 176, 177, and 178.

(Exhibits 176, 177, and 178 admitted into the record.)

CHAIRMAN EDGAR: And the witness is excused. Although we will be seeing you back again; correct?

THE WITNESS: Yes, you will.

CHAIRMAN EDGAR: Okay. Thank you. And I'm ready to move on if you are, so your witness.

MR. ANDERSON: We are. Thank you very much. FPL would call as its next witness Mr. Steve Jenkins, who I think the record will show has been sworn.

MR. GUEST: May I raise an administrative matter, Madam Chairman?

CHAIRMAN EDGAR: You may.

MR. GUEST: It's beginning to look like

there's a possibility that we're running slower than we thought we were.

CHAIRMAN EDGAR: It is beginning to look that way, yes.

MR. GUEST: And we have witnesses that are fixing to hop on airplanes from far away, and I think that I've got to call one of them in the coming 30 minutes to say should he come or not. And I think it's about time to try to get there on this issue.

MR. LITCHFIELD: Madam Chairman, Wade Litchfield for FPL. I wonder if it might be appropriate to take maybe a five-minute recess, because I think there may be a discussion that we can have with counsel.

CHAIRMAN EDGAR: Sure. I had actually hoped that maybe some of those discussions had been worked out at lunch, but I did not ask. And I apologize for that. I probably should have before we had the next witness.

MR. GUEST: We had substantial discussions at lunch, and there was a proposal to put it off until now, essentially. That's what happened.

CHAIRMAN EDGAR: Okay. Well, then let's take a few minutes and see if we can --

MR. KRASOWSKI: Excuse me, Madam Chair.

CHAIRMAN EDGAR: -- work out some efficiencies. Mr. Krasowski, yes.

MR. KRASOWSKI: Yes, ma'am. We have an interest -- I have an interest as well in the sequence of witnesses, so if we might be able to listen in to the discussion.

CHAIRMAN EDGAR: Mr. Krasowski, I would absolutely ask you to join our staff and the other attorneys involved in the proceedings. Thank you.

(Short recess.)

CHAIRMAN EDGAR: Are we ready?

MR. GUEST: Yes.

CHAIRMAN EDGAR: Okay. Do we have --

MR. LITCHFIELD: Madam Chairman --

CHAIRMAN EDGAR: -- some agreement, some compromise?

MR. GUEST: What happened is that we have been unable to reach agreement, and I think we need some assistance from the Chair in getting there.

What happened, as you recall, the last day that we were here is that Mr. Schlissel was examined at great length, and there were a few questions left, but he had to go and catch his plane. And he went back up to Cambridge, and he's waiting for a phone call about whether to come back here for the five questions. He was taken out of order and in the hope that --

CHAIRMAN EDGAR: In an effort to accommodate.

MR. GUEST: Indeed. Oh, indeed, he was, and we appreciate that. And what we're trying to do is look at the testimony of Mr. Sim, and having done that, make a decision about whether we even need to bring him back, whether we need to bring Dr. Schlissel back. There are a number of rebuttal witnesses that don't deal with anything related to him. Mr. Schlissel deals solely and exclusively with the matter of carbon costs. It doesn't relate to the testimony of Mr. Hicks, Mr. Jenkins, Mr. Kosky, or Mr. Rose.

So what we would like to do is take them out of order, in the hope that we will come up with a way to not have to bring -- well, take -- if necessary -- I think there's a question is it even necessary alone. If we end up getting our case in chief done tomorrow, which, at the rate we're going, may even not happen, to hold open the option of just not calling David Schlissel, and if there's still a little time left tomorrow, going into rebuttal on issues that are unrelated to him, and that might avoid him leaving home in Cambridge at all. That's what we're seeking to try to do.

MR. LITCHFIELD: Madam Chair, if I might respond.

CHAIRMAN EDGAR: Mr. Litchfield.

MR. LITCHFIELD: If I'm looking at the order of witnesses as it's laid out here, we've finished with Mr. Hicks. We're taking Mr. Jenkins and Mr. Kosky, which we expect we'll be able to do this afternoon. And Mr. Sim, I'm told the questions for Mr. Sim on his direct are very few.

There's also a possibility I think that we should explore right now as to the possible stipulation of Mr. Yeager, both as to his direct and rebuttal. My understanding is that there are perhaps few, perhaps no questions of any party for Mr. Yeager, subject, of course, to the Commissioners' questions.

The next one, two, three, four, five witnesses are either all stipulated or have already appeared, both on direct and rebuttal, which takes us to very quickly, I think, tomorrow into the three witnesses of the intervenors, Mr. Furman, Plunkett, and Schlissel. Now, we're amenable to taking up Mr. Schlissel first and Mr. Plunkett second and Mr. Furman third, any order that Mr. Guest would suggest in terms of his witnesses. But I think it is a certainty that we will get to all three of these witnesses tomorrow.

Now, as to whether Mr. Schlissel needs to come back, we had offered previously, and in talking with Mr. Guest here today, we've renewed the offer to simply submit Mr. Schlissel's deposition into the record and forgo any further questions and save him the trip. But I would be reluctant to hold out essentially an option to Mr. Guest to decide when and if Mr. Schlissel is going to appear, to allow him again at his option to place him toward the end of the witness order.

And I think it is incorrect to suggest that the witnesses that we have on rebuttal have nothing to do with Mr. Schlissel's testimony. In fact, Mr. Kosky, Mr. Sim, Mr. Rose, and Mr. Silva all have to do with Mr. Schlissel's testimony.

So my view is, Mr. Schlissel ought to -- if he's going to testify, he ought to plan to be here tomorrow, and we will make every accommodation to take him out of order tomorrow, or if they don't need him to come back, we'll put in the deposition, and he will not have to make the trip.

CHAIRMAN EDGAR: Mr. Guest, that seems reasonable to me. We offered the option at the close of the last day, the prior day of the proceeding, to enter the deposition or to have him return. If FPL has renewed their willingness to go with either of those options, I renew mine as well to go with either of those.

For scheduling purposes, also, I think we can go till 7:00, 7:30ish this evening. Tomorrow I have an appointment, so that I cannot go beyond 4:00 tomorrow. Therefore, we will not be going beyond 4:00 tomorrow. Close out that thought. And I apologize for that. I've moved as much as I can, and I know that everybody else has as well.

So realizing that I think we can go a little later than usual this evening, the possibility -- let's take up the easy thing first. Witness Yeager, there has been a suggestion that his direct and rebuttal could be stipulated. So, Commissioners, I will ask you to consider that and ask our staff, do we have questions --

MS. BRUBAKER: Staff has no questions.

CHAIRMAN EDGAR: So staff would be able to stipulate. Commissioners? Mr. Krasowski?

MR. KRASOWSKI: No questions of Mr. Yeager.

CHAIRMAN EDGAR: No questions for Mr. Yeager.

MR. GUEST: There was a suggestion that -- or a representation that we weren't going to ask any questions, and I don't think that's accurate.

CHAIRMAN EDGAR: Actually, if that was the representation, I missed it, and I was not representing that.

MR. LITCHFIELD: I was, and if I'm mistaken, I apologize, but that certainly had been my understanding.

CHAIRMAN EDGAR: Okay. And, Mr. Guest, I was going to ask you the same question. So --

MR. GUEST: We are going to have some questions.

CHAIRMAN EDGAR: Okay. Then I think where we are is, we will take here in just a moment Mr. Jenkins. We will get as far as we can with Jenkins, Kosky, Sim, and -- is Mr. Yeager here today? Maybe we'll get there, maybe not.

And so the question comes back to you Mr. Guest, as to whether we have Mr. Schlissel appear tomorrow to finish the cross and redirect or admit his deposition testimony in lieu of.

MR. GUEST: I'm going to need a minute to decide that. I didn't except to have that option.

CHAIRMAN EDGAR: Okay. Do you want to decide that now, or do you move on and tell us later?

MR. GUEST: Well, he's supposed to catch a plane in 20 minutes.

CHAIRMAN EDGAR: Then we'll take a moment in place.

(Off the record briefly.)

CHAIRMAN EDGAR: All right. Back on the record. I apologize. I didn't realize you were ready. Okay. Where are we?

MR. GUEST: Thank you for indulging us and giving us the time to work this through. We are not going to call Dr. Schlissel. We're going to leave him in Cambridge. He's got personal issues up there. It's probably a really good idea to be doing this for him too. So we just won't call him, and we'll just put in the deposition.

CHAIRMAN EDGAR: Ms. Brubaker, any concerns or other issues that we would need to address? We do have the matter of the exhibits, and we will need to put in the deposition.

MS. BRUBAKER: Provided, of course, no other party has any questions for Mr. Schlissel, staff is happy to stipulate to his existing testimony as well as his deposition in lieu of further cross. As far as entering his testimony and current exhibits in the record, we can simply take those up, if you like, when he comes up in turn as listed on page 4 of the Prehearing Order, or we can take them up now if that's the --

CHAIRMAN EDGAR: We'll do it in order so that I don't get confused.

MR. LITCHFIELD: Madam Chairman, I have one other --

CHAIRMAN EDGAR: Mr. Litchfield.

MR. LITCHFIELD: I have one other suggestion, again, to potentially save Mr. Plunkett a trip down as well. We would also be amenable to forgoing cross and putting his deposition into the record and stipulating his testimony in as well.

MR. GUEST: I think Mr. Plunkett needs to be here.

CHAIRMAN EDGAR: Okay. All right.

MR. GUEST: So we're going to do him for sure tomorrow, and if we're going to do him for sure tomorrow -- is that our understanding, Madam Chairman?

CHAIRMAN EDGAR: I think we can get there. I'll need everybody to work with me. Okay?

MR. GUEST: Well, of course, I will work in every way possible, but it wasn't sure how for sure that felt.

CHAIRMAN EDGAR: It's not all within my control, but I will certainly work to accommodate that.

MR. GUEST: Okay.

CHAIRMAN EDGAR: Mr. Krasowski, did you have a question or concern before we move on?

MR. KRASOWSKI: No, ma'am. Everything is just fine right now.

CHAIRMAN EDGAR: Thank you.

Okay. Mr. Anderson.

MR. ANDERSON: Thank you, Chairman Edgar.

CHAIRMAN EDGAR: Thank you.

Thereupon,

STEPHEN D. JENKINS

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

DIRECT EXAMINATION

BY MR. ANDERSON:

Q. Good afternoon, Mr. Jenkins.

A. Good afternoon.

Q. Have you been sworn?

A. Yes, I have.

Q. Would you please tell us your name and your business address?

A. My name is Stephen Jenkins, and my business address is 4350 West Cypress Street, Tampa, Florida 33607.

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

A. I'm employed by the engineering firm CH2M Hill, Inc. I am their Vice President, Gasification Services.

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

A. Yes, I have.

Q. Did you also cause to be filed errata to your testimony on March 13, 2007?

A. Yes, I did.

Q. Do you have any further changes or revisions to your prefiled direct testimony other than the errata sheet?

A. No, I do not.

Q. With those changes, if I asked you the same questions contained in your prefiled direct testimony, would your answers be the same?

A. Yes.

MR. ANDERSON: Madam Chairman, we ask that Mr. Jenkins' prefiled direct testimony as amended by the errata be inserted into record as though read.

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

MR. ANDERSON: We note that Mr. Jenkins has no exhibits or attachments to his direct testimony.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF STEPHEN D. JENKINS

DOCKET NO. 07_____ - EI

JANUARY 29, 2007

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

A. My name is Stephen D. Jenkins. My business address is 5340 W. Cypress Street ~~URS Corporation, 7650 West Courtney Campbell Causeway~~, Tampa, Florida 33607.

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

A. I am employed by CH2M Hill, Inc. as Vice President, Gasification Services. ~~URS Corporation ("URS") as the IGCC Technology Leader~~.

Q. **Please describe your educational background.**

A. I received a Bachelor of Science in Chemical Engineering from the University of South Florida in 1976.

Q. **Please describe your work and professional experience.**

A. I have over 30 years of experience in the power industry, primarily in the design, permitting, and operation of large coal-fired and oil-fired power plants, emission control systems for coal-fired power plants, and Integrated Gasification Combined Cycle ("IGCC") power plants. Prior to joining CH2M Hill ~~URS~~, I worked for TECO Energy, as well as several of its subsidiaries, including Tampa Electric Company and TECO Power Services. I worked in a number of areas in these companies, including power plant operations, power plant engineering, fuels, environmental planning, finance, governmental affairs and regulatory affairs. I also served as the

Deputy Project Manager for the Polk Power Station IGCC project, one of the two operating IGCC power plants in the U.S.

Q. Where are you currently employed?

CH2M Hill

A. I am employed by ~~URS~~ in the Tampa, Florida office.

Q. What do you do in that job capacity?

A. I am responsible for leading our IGCC and gasification business in the power industry, across the U.S. My job responsibilities include business development, as well as managing large projects in related technical areas. This includes a number of projects where we are providing environmental permitting, planning, feasibility and engineering services. I personally have been involved in the feasibility engineering, permitting or design of ten different coal gasification and IGCC projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to show that Florida Power & Light Company's ("FPL") selection of ultra-supercritical pulverized coal ("USCPC") technology for the proposed FPL Glades Power Park ("FGPP") is a more prudent one than had they selected IGCC technology. This is based on an overall analysis and comparison of factors that include technology maturity, efficiency, reliability, power generating capability, operational history and environmental performance.

Q. What is IGCC technology?

A. IGCC is a developing technology for generating electricity using coal or other similar feedstocks. Unlike conventional pulverized coal ("PC") fired power plants where the coal is combusted in a boiler, and steam is produced, turning a turbine generator to produce electricity, the IGCC process converts coal into a synthetic gas, or syngas, which, after cleaning, can be burned in a gas turbine generator. An IGCC facility combines gasification technology from the chemical industry with combined cycle power generation technology from the power industry. Air, steam, nitrogen and other streams are integrated between the gasification and combined cycle "islands"; hence, the name Integrated Gasification Combined Cycle, or IGCC.

Q. How much of your background is involved in IGCC technology?

A. I have worked with IGCC technology for 15 years, about half of my career.

Q. How much of your current job is spent working on IGCC issues?

A. About 75% of my current work applies directly to IGCC technology.

Q. Have you written any articles, or done any presentations, on IGCC technology?

A. Yes. I have written articles and made many presentations on IGCC technology over the past 15 years.

Q. Do you consider yourself an expert in IGCC technology?

A. Yes. As I noted, I was the Deputy Project Manager for the Polk Power Station IGCC project, one of the two operating IGCC power plants in the U.S. Since then, I have been directly involved in a number of IGCC and gasification projects across the U.S. This includes providing environmental permitting, technical feasibility, and engineering services for a number of these modern IGCC and gasification plants that are in development at this time. In addition, I serve on the

Electric Power Research Institute's CoalFleet for Tomorrow Program IGCC Experts Group.

FGPP SITE

Q. Can you please describe the technology that FPL is proposing to use at FGPP?

A. The technology to be used at FGPP is USCPC technology. In this kind of a power generation technology, coal is crushed to a fine powder, and blown into a boiler with air. The coal-air mixture burns at temperatures of over 2,500 °F. Heat from the combustion is transferred to the water that is pumped through the boiler tubes, turning it to steam at very high temperatures and pressures. The operating pressure of coal-fired power plants is classified as either subcritical pulverized coal ("SPC") or supercritical pulverized coal ("SCPC"). SPC and SCPC refer to the state of the water and steam that is used in the steam generation process. SPC power plants utilize pressures below the critical point of water in which there is a distinct difference in the state of the water and the steam. The critical point of water is 3,208 psia and 705 °F. At this "critical" point, there is no difference in the density of water and steam. At pressures above 3,208 psia, heat addition no longer results in the typical boiling process in which there is an exact division between steam and water. The fluid becomes a composite mixture throughout the heating process. The majority of the boilers in the U.S. utilize subcritical technology, typically with steam temperatures up to 1,050 °F and pressures up to

2,400 psia. These units utilize a steam drum and internal separators to separate the steam produced in the boiler from the water circulating in the boiler tubes. Supercritical units do not utilize a steam drum, since there is no way to separate steam from the steam-water mixture.

In SCPC boilers, all of the water introduced into the boiler is turned into the supercritical steam-water mixture. Operation at the higher supercritical pressures is more efficient than for subcritical boilers. The U.S. Department of Energy ("DOE") has defined USCPC steam cycles as operating pressures exceeding 3,600 psia and main steam superheat steam temperatures approaching 1,100 degrees F. This is even more efficient than conventional SCPC technology. FGPP plans to utilize the more efficient USCPC technology.

The high pressure steam is then piped to the steam turbine, where it turns the turbine blades at high speed. The turbine is connected on a shaft to a generator, which produces the electricity. The steam is condensed to water, and then pumped back to the boiler to be turned into steam again.

In the boiler, the ash in the coal is converted primarily to fly ash, with some falling to the bottom of the boiler; it is called bottom ash. The bottom ash is cooled in a water bath and removed for re-use in industry or it can be safely stored in a lined landfill. The fly ash is removed in the emission control system. In the boiler, low-NOx burners, with overfire air, are an industry-standard design for minimizing the formation of NOx during combustion. The emission control system for a coal-fired power plant typically includes a selective catalytic reduction ("SCR") system for reducing emissions of nitrogen oxide ("NOx") emissions, a sorbent injection system for capture of mercury, a fabric filter for removal of the fly ash and captured mercury from the exhaust gas stream, a flue gas desulfurization ("FGD") system for removal of the sulfur dioxide ("SO_2") produced when the sulfur inherent in the coal is also combusted, and a wet ESP for removal of fine particulates. These are all included in the design of FGPP. Following the emission control system, the cooled, cleaned exhaust gas exits through a stack.

Q. **Is the technology that FPL is proposing to use a proven and reliable technology?**

A. Yes. The USCPC technology that FPL is proposing to use is proven worldwide and is a reliable technology for power generation.

Q. **Are other facilities in the United States and around the world using this technology?**

A. Yes. There are approximately 160 supercritical generating units in operation in the U.S., with over 500 operating worldwide. This number includes 17 plants worldwide using the more advanced USCPC technology proposed for FGPP. Several have been operating almost nine years, and operating data shows that these units have been very reliable.

Q. **Are you a proponent of IGCC technology?**

A. Yes. I am. Although IGCC is still in the development phase of, I think that it will be able to significantly reduce emissions and provide low cost electricity, once it is proven at a large, commercial scale.

Q. Has IGCC been used successfully for other power plants in the United States and around the world?

A. Yes. Although its application was not initially successful due to difficult start-ups and low plant availability, these IGCC facilities can now be considered as successful.

Q. Please describe some of the currently existing IGCC plants in the United States and around the world.

A. There are four coal-based IGCC plants in operation worldwide. They include Tampa Electric Company's Polk Power Station near Mulberry, Florida; SG Solutions' Wabash River Generating Station in West Terre Haute, Indiana; Nuon's Willem-Alexander Centrale Station in Buggenum, The Netherlands; and the Elcogas Puertollano Plant in Puertollano, Spain. There was a fifth plant, in the U.S., but it is no longer in operation.

Q. How big are those facilities?

A. All four of these are single train gasification plants, each with a net output in the range of 250-260 MW.

Q. Has anyone built a 1,960 MW facility using IGCC?

A. No.

Q. What is the largest facility that has been built using IGCC?

A. The largest coal-based IGCC plant is sized at 260 MW (net).

Q. Do you know of any proposed 1,960 MW or larger IGCC facilities?

A. No. I do not.

Q. What is the largest size IGCC plant that is commercially available?

A. The largest size being commercially available is called the 600 MW net "reference plant." This size is being offered by five different IGCC technology providers, although the specific commercial and environmental guarantees are not publicly available. This 600 MW net size incorporates several gasifiers to produce two to three times the amount of syngas produced at each of the demonstration facilities, which is sufficient to fully load two of the modern gas turbines being commercially offered for syngas service. Integrated together, the net output is about 600 MW. It will first be very important to prove the coal gasification technology at this larger scale, as well as proving these new types of syngas-fired gas turbines at commercial scale. Once that has been done successfully, and I believe that it will be, these companies will begin to offer large designs. That is likely to happen about six to eight years from now after this next generation of IGCC plants has gone into service.

Q. Have the current IGCC facilities been funded by their governments?

A. Yes. All four of the operating plants received significant amounts of co-funding from their respective federal governments. This is because both private industry and the governments were very interested in developing IGCC and demonstrating it at commercial scale, but neither was able to bear the entire costs of these plants. In the case of Polk Power Station, the DOE funded 20-25% of the capital cost of the plant, as well as some of the operating costs during the demonstration period.

Q. **What has been the track record of these facilities?**

A. The initial start-up at all of these plants was very difficult and the overall plant availability for each of these plants was low for the first several years. Since then, many operational problems have been solved, some equipment has been removed or modified, and many of the "bugs" have been worked out.

Q. **Are all these facilities still online and functioning?**

A. No. Only four of the five are in operation.

Q. **Is the facility in Nevada still online and functioning?**

A. No. The gasification facility at the Piñon Pine IGCC demonstration plant in Nevada is no longer functioning, although the power block is operating using natural gas as a fuel.

Q. **Why is the Nevada facility not online and functioning?**

A. This IGCC plant was developed as part of the DOE's Clean Coal Technology Program, as were the Polk Power Station and Wabash River IGCC facilities. The gasification technology used at the Piñon Pine IGCC demonstration plant was not successful, and was shut down following initial start-up and operation.

Q. **How reliable are IGCC facilities?**

A. The four operating IGCC plants described previously had significant start-up and initial operation problems. Reliability in the first three to four years was much lower than planned. Since then, many of the design and operation issues have been successfully resolved. Availability values are much higher, although none of these plants have achieved sustained reliability values of 85%, as planned. In its ninth year of operation, Polk Power Station achieved 82% availability of the overall IGCC plant. Wabash River reached about 78% availability in its seventh year of operation. The Nuon IGCC plant reached about 78% availability in its eleventh year of operation, and Puertollano's availability peaked at about 60% during its fifth year of operation.

Q. Why do IGCC plants have problems with reliability?

A. The four IGCC plants all have single-train gasification islands. Whenever a single train is removed from service due to operational problems, there is no syngas available for combustion in the gas turbines. At that point, unless a back-up fuel is used, the power plant must be shut down. The use of a single train in these demonstration plants is a major contributor to the low reliability of IGCC plants. Other reasons for low reliability include corrosion and erosion of gasifier refractory, requiring an outage for replacement, corrosion of process piping, plugging of syngas heat exchangers that leads to outages for cleaning, corrosion of process piping, slurry pump problems, and miscellaneous power block problems that can occur in any combined cycle plant. A reliability issue that is somewhat unique to syngas use relates to high rotor torque. Gas turbines are designed to handle the combustion of natural gas. Since syngas has a much lower heating value, a much greater amount of syngas is required to fully load the gas turbine. This additional rotational stress has had negative impacts on syngas-fired gas turbine reliability.

There are many gasifiers operating successfully worldwide. They are typically used for producing a syngas that can be further processed to produce hydrogen for refineries or to make ammonia for fertilizer manufacture, not to produce electricity. Some of these facilities, particularly those with spare gasifier trains, reach availability values in the high 90% range. Some of the successful gasifiers also use refinery bottoms, like asphalt, as a feedstock. Such liquid feedstocks require little handling and preparation, versus the coal handling and coal grinding systems required in a coal-based IGCC plant. Operating a gasifier by itself is significantly less difficult and complicated than when using a gasifier as an integrated part of a complex IGCC plant that produces electricity. It is important to note that the "integration" part of IGCC is very difficult to design for and to operate. All of these components in the gasification and power block islands must be operated interdependently. The failure of one system often leads to the entire plant being shut down. It is very different from having to operate only a gasifier. That is why the reliability of gasifier-only facilities is greater than those of IGCC facilities.

Q. Has there been an effort to improve the performance of IGCC?

A. The next generation of IGCC plants is being designed using the lessons learned from the four operating plants. Some of the key design enhancements to improve reliability include using two 50% sized gasification trains (instead of one 100%-sized train), and even adding a third gasifier train as a spare, better integration between the gasification island and the power block, better gasifier refractory materials, design without convective syngas coolers, and upgraded gas turbine burners and materials for syngas service. These design improvements, along with other lessons learned, are expected to provide for easier initial start-up, as well as higher availability. Use of a spare gasification train is expected to provide up to 90-92 % availability, but adds to the cost of the facility. Moreover, these design enhancements will not be placed into service until the 2011-2013 timeframe, so that it will be six to eight years from now (allowing for start-up and initial operation) before we see whether IGCC reliability can be improved to levels greater than 85%.

Q. **Is IGCC technology progressing as quickly as you would like?**

A. No. It is not. The first generation of IGCC plants went into service between 1994 and 1998. The second generation will not go into service until 2011-2013, a time delay of about sixteen years. When we designed and built Polk Power Station, it was our expectation that the technology would be embraced by the industry, and that by now we would have had the critical second generation of IGCC plants already in operation, in order to prove the technology on a large, commercial scale.

Q. **Does IGCC need more investment in research?**

A. Yes. IGCC still requires a significant amount of investment in research and development. That is why individual power companies, the Electric Power Research Institute ("EPRI"), and the U.S. DOE are still planning and funding such research and development ("R&D") to support further IGCC technology development. In the Coal Technology Roadmap developed by EPRI and Coal Utilization Research Council, a total of $5.2 billion of R&D and demonstration of promising improvements is still needed to provide for the needed IGCC enhancements. These include basic system development, efficiency improvements, use of new air separation technology, improvements in gasifier refractory materials, new types of particulate removal devices, slurry pump enhancements, gasifier skin temperature monitoring systems, more efficient emission control systems, and gas turbines that can handle high hydrogen concentration syngas. Of this $5.2 billion, about 60% would be needed from the federal government. In addition, the Energy Policy Act of 2005 provides for additional IGCC and gasification R&D through the U.S. DOE's Clean Coal Power Initiative, as well as tax incentives and loan guarantees to promote further demonstration of IGCC and gasification technology. This legislation specifically recognizes the continuing need for R&D and co-funding or economic incentives for IGCC technology to succeed at large, commercial scale.

Q. When do you think IGCC will be commercially available?

A. IGCC is commercially available from IGCC technology suppliers at this time, based on a 600 MW net IGCC "reference plant" design. However, the plant would not be able to be started up for five to six years from the time you began the IGCC project. For example, if you began a 600 MW net IGCC reference plant project today, it would be late 2012 to 2013 at best before the plant was ready for startup. Any changes to the basic reference plant design would take longer to design, and may not even be commercially available.

If IGCC technology were to be selected for this project, FPL would likely use the largest size plant available, in order to take advantage of economies of scale, just as it has already done in choosing large 980 MW (net) USCPC units. For IGCC, the closest match to meet the 1,960 MW (net) value would be to use a 3x3x1 configuration such as the one referenced in the study jointly conducted by FPL and Black & Veatch. This study is noted as Document No. DNH-2 in the testimony provided by Mr. Hicks of FPL. However, as I noted previously, the largest size IGCC facility that is being offered by the IGCC technology suppliers is the 600 MW (net) reference plant. Therefore, a non-standard 3x3x1 configuration, if commercially available, would take even longer to be designed and constructed.

IGCC technology suppliers, in alliance with engineering firms and power block suppliers, are offering the technology today with limited guarantees on performance and emission limits. Although about a dozen power companies are going forward with IGCC projects, none have yet finalized a contract for a complete reference plant, so that such terms and conditions, as well as the guarantees, have not yet become publicly available. Due to the higher cost of IGCC compared to SCPC technology, many of these projects are counting on the financial incentives provided by state and federal legislation in order to help make the projects commercially feasible.

Q. Do you think that IGCC technology is commercially ready?

A. Although IGCC is commercially available, it will not be commercially ready or proven on a large scale for at least another six to eight years, once this next generation of IGCC plants has gone into service and had an opportunity to work through initial start-ups and reach steady operation.

Q. Do you have concerns regarding the use of IGCC technology at FGPP?

A. Yes. I would have some concerns with the use of IGCC technology at this site.

Q. What are some of your concerns with the use of IGCC technology at the site?

A. First, I would be concerned with the potential for reliability problems. FGPP is being designed for 92% reliability, which is commercially available and proven with SCPC technology. As noted previously, such high reliability levels have not yet been demonstrated by existing IGCC power plants, and it will be six to eight years before the presently planned IGCC plants are able to prove whether the intended design enhancements can provide for improved reliability.

Second, FGPP is being designed to produce 1,960 MW net, using two USCPC generating units. As noted previously, IGCC is only commercially available, but not yet "ready" or "proven," at the 600 MW net size. It would take more than three IGCC reference plants to do the job of the two USCPC units. At the present time, the three IGCC technology supplier alliances are at their busiest ever. I am concerned that the supplier alliances would not be able to support the engineering, procurement, and construction of three concurrent 600 MW IGCC reference plants.

Third, it takes five to six years to design, permit, and construct an IGCC plant. If FPL were to start now, it would be late 2012 or 2013 at best before the first IGCC plant could be ready for operation.

Q. Do you have reliability concerns with an IGCC plant?

A. As I noted previously, the existing IGCC power plants demonstrated poor reliability in the initial years of operation, with only medium reliability values at maturity. Even though designs are including information from lessons learned, it will still be another six to eight years before we know whether IGCC can provide the high reliability values that are presently being demonstrated by SCPC plants worldwide.

Q. Why do you have reliability issues with an IGCC plant?

A. These concerns are based on the historical poor to moderate performance of the four operating IGCC plants worldwide, and the fact that the potential for higher reliability will not be known for another six to eight years.

Q. Why is the plant that FPL is proposing more reliable than an IGCC plant?

A. PC technology has been in commercial operation worldwide for about 100 years. IGCC has only been in commercial operation worldwide for about 13 years. There are more than 300,000 MW of PC capacity in the U.S. There are only 510 MW of IGCC capacity in the U.S. PC technology is proven at a large scale in thousands of applications. PC units (whether SPC, SCPC or USCPC) have demonstrated high reliability. The operation of a PC unit does not require the interdependent operation of a multitude of individual chemical and mechanical processes as does IGCC. IGCC plants take several days for a cold start, due to limitations in the rate of heating up of the gasifier (to protect the refractory from thermal cracking), as well as cooling the air separation "cold box" to well below freezing temperatures. Together, these have significant negative impacts on the total number of days per year that the IGCC plant can operate at full load. IGCC plants have suffered from these problems and have exhibited reliability problems. PC plants require several days for a cold start, but these would typically occur two or three times per year. IGCC plants also have a history of many warm or hot starts. While these startups do not take as long, they still impact negatively on IGCC unit reliability. Two of the IGCC plants being planned at this time for operation in the 2011 to 2012 timeframe have noted in their air permit applications the potential for over 60 startup and shutdown events per year, far more than what is normal for PC units. Taking into account all of these reasons, PC units are expected to continue to provide higher reliability than IGCC units.

Q. Is there a proposed IGCC facility in Orlando?

A. Yes. An IGCC plant is being planned in the Orlando area.

Q. Can you compare that facility to the proposed FGPP?

A. The Orlando Gasification Project ("OGP") is being developed by the Orlando Utilities Commission ("OUC") and Southern Power Company ("Southern"), a subsidiary of the Southern Company, which is a large utility holding company. OGP is planned to start up in 2010. The OGP proposes to demonstrate the Kellogg Brown and Root ("KBR") transport gasifier in IGCC configuration. The KBR technology has been developed from technology used in catalytic crackers in the refinery industry. OUC and Southern expect this new IGCC technology to provide for higher efficiencies, especially when applied to low quality coals. The KBR technology has been pilot tested at the approximately six MW scale at the Power Systems Development Facility in Wilsonville, Alabama, adjacent to

Alabama Power Company's Gaston Steam Plant. The KBR technology is an air-blown gasification technology, unlike the oxygen-blown gasification technology being commercially offered by GE Energy, ConocoPhillips and Shell (although it can operate in oxygen-blown mode). In addition, OGP will use Powder River Basin subbituminous coal railed in from Wyoming, unlike the higher quality bituminous coal planned for FGPP.

OGP will be sized for a net output of only about 285 MW. This is about one-sixth of the power generation capacity to be produced by the USCPC generating units planned for FGPP. Overall, OGP will be much smaller in scale than FGPP, and will use a power generation technology that is not yet proven at large commercial scale.

Q. Can you compare the efficiency?

A. The efficiency of OGP will not be known until it has been in operation for at least a year, meaning some time in 2011. For comparisons of SCPC and IGCC efficiency, I refer you to the study jointly conducted by FPL and Black & Veatch. This study is noted as Document No. DNH-2 in the testimony provided by Mr. Hicks of FPL.

Q. Can you compare the Capital Cost?

A. Comparisons of the capital costs of different projects are difficult, due to differences in what each estimate includes or excludes. According to the DOE, the cost of the OGP will be $557 million. However, I understand from Southern that this amount only includes the gasification portion of the project, and not the combined cycle power block. Therefore, it is not possible to make a comparison of capital costs with FGPP. For comparisons of SCPC and IGCC cost, I refer you to the study jointly conducted by FPL and Black & Veatch. This study is noted as Document No. DNH-2 in the testimony provided by Mr. David Hicks of FPL.

Q. Can you compare the technology status?

A. As noted previously, USCPC technology is proven on a large commercial scale. IGCC technology is still in development, and is not yet mature. OGP will only demonstrate the KBR technology at about half of the IGCC reference plant size and one-seventh the size of FGPP.

Q. Can you compare the scale-up required?

A. The USCPC technology proposed for FGPP will not require any technology scale-up, as it is already in commercial operation worldwide at the proposed scale. The capacity of the KBR gasifier will need to be scaled-up over fifty times.

Q. Has the Orlando facility received government funding?

A. OGP is receiving co-funding under Round two of the DOE's Clean Coal Power Initiative.

Q. How much funding will it receive under this program?

A. According to the DOE, it will be providing $235 million in co-funding for OGP.

Q. How effective is the plant that FPL is proposing in reducing emissions?

A. The emission control systems planned for the USCPC power generation technology proposed for FGPP will be designed to provide state-of-the-art emission reductions.

Q. Can you please discuss each of the emissions, such as nitrogen oxides, sulfur dioxide, mercury and other emissions in terms of how they would be handled at an IGCC plant versus the proposed FPL plant?

A. As I noted previously, an IGCC facility converts coal to a syngas, which is then cleaned and combusted in the gas turbine. The reduction of emissions from an IGCC plant occurs pre-combustion, so that pollutants are removed or reduced before the syngas is burned. This is different from a PC plant, where most of the emission reductions are achieved post-combustion, meaning that emissions are removed from the exhaust gas after the coal is burned. The table below describes the typical emission control methods for the USCPC technology proposed for FGPP and for IGCC.

	FGPP	**IGCC Plant**
NOx	Low-NOx burners and overfire air to reduce formation of NOx, along with Selective Catalytic Reduction (SCR) to remove NOx from the flue gas	Syngas humidification and injection of diluent nitrogen (for oxygen-blown IGCC systems) into syngas just prior to the gas turbine or in the burners
SO_2	Wet Flue Gas desulfurization (FGD) system	Removal of hydrogen sulfide from syngas reduces SO_2 emissions when the syngas is combusted in the gas turbines
PM/PM10	Use of fabric filter to remove fly ash from the flue gas, along	System can use wet carbon scrubber, hot gas cyclone, and/or

	with minimizing fine particulate through removal of SO_3 droplets in a wet ESP	high temperature, high pressure candle filter
CO	Good combustion practices	Good combustion practices
VOC	Good combustion practices	Good combustion practices
SAM	FGD system and wet precipitator	Fuel sulfur specification and SO_2 emission control
Mercury	Co-benefits removal in ESP or fabric filter, and in FGD system, along with sorbent injection upstream of the fabric filter	Removal in slag, carbon scrubber, pre-sulfided activated carbon bed, and acid gas removal system recirculating solvent

Q. Does reliability affect emissions? In other words, if you have to start up a plant more frequently, does that affect emissions?

A. Yes. Overall plant reliability can affect overall emissions. When a PC power plant starts up, the boiler is fired with coal at a very low throughput, and then it gradually ramps up to a higher throughput. When the proper steam conditions are reached, the steam is routed to the steam turbine for power generation, although at a minimum load. Then the coal throughout, steam production and power generation are gradually ramped up to full load.

During the time a plant is starting up, coal is being consumed without any power generation, until steam conditions are right for sending it to the steam turbine. Power plants operate at their most efficient point at high loads. During the start-up process, the unit operates at a lower efficiency. This means that more coal is used for a unit of power generated than it would at a high load. Since more coal is being consumed, more emissions are produced per unit of power generated. Fortunately, PC units have a fairly short start-up time period. In starting up a coal-fired unit, steam requirements are typically met using a small, auxiliary boiler. These boilers use fuel oil or natural gas, and contribute to the unit's overall emissions.

IGCC units have a different start-up profile. As noted previously, a cold start-up on an IGCC power plant can take several days. During this time, large amounts of coal can be consumed in the gasification process while the emission control systems are being started up. Clean or partially cleaned syngas is flared. Emissions from the flare can be substantial, depending on the state of operation of the emission control systems and the total time of flaring. Combining these technical issues with a somewhat lower reliability of IGCC versus PC technology, an IGCC plant could actually produce more emissions on an annual basis than a PC unit, even though it may have a lower emission rate on a lb/MWh or pounds per million Btus of heat input basis.

Q. Based on the technology today, do you believe that the emissions would be better for an IGCC facility versus the proposed FPL power plant?

A. Not necessarily. The proposed emission rates for some of the pollutants for proposed IGCC units are lower than those proposed for FGPP. However, due to the impacts of all of the start-up and shutdown cycles inherent with IGCC facilities, there can be some substantial overall increases in overall emissions from an IGCC facility that are not accounted for in these proposed emission rates. URS analyzed the emission data in the air permit applications for several proposed IGCC facilities, as well as similar data for FGPP. We looked at the proposed emission rates in lb/MWh and then calculated what those values would be when incorporating the emissions from the start-up and shutdown cycles. What we found was that for FGPP, the emissions from start-up and shutdowns increased the overall emission rates by no more than five %. However, it was very different for the IGCC units. We saw that the emission rates for the IGCC units could actually be increased by an average of 38%, if all of the potential start-up and shutdown emissions are accounted for. Based on that analysis, it is possible that an IGCC unit with an emission rate lower than that for a PC unit may actually have an equal or greater potential emission rate, due to the differences in the start-up and shutdown issues. I would not expect that in actual operation, that all of these start-up and shutdown cycles would occur. The air permit applications were written in a way so as not to constrain the units' operation, so that the number of start-up and shutdown cycles was maximized. For an actual comparison, each unit's characteristics would have to be analyzed to determine the overall impact of start-ups and shutdowns.

Q. Is IGCC "CO_2 Capture Ready"?

A. When discussing IGCC technology, the term "CO_2 capture ready" means that the IGCC plant is technically ready to be converted to produce a concentrated stream of CO_2 (through the water shift reaction), and that the CO_2 can be easily captured and removed from the syngas stream. An IGCC plant is not capture ready unless it has been designed from the beginning to provide for these significant modifications. IGCC by itself is not "CO_2 capture ready."

Q. What changes are needed to make an IGCC plant CO_2 capture ready?

A. First, the IGCC technology being used, as well as the physical plant itself, must be capable of the addition of a water shift reactor. This is the primary process where the syngas is processed and converted to a stream with high concentrations of both hydrogen and CO_2. Since the water shift reaction is exothermic, steam is typically produced for use elsewhere in the process. The IGCC plant design must account for the addition of this water shift reactor and to have a proper place to route this low pressure steam.

Then there must be room for the addition of a very large CO_2 capture/removal system. While the acid gas removal systems typically used for H_2S removal can also be used to absorb some of the CO_2, they are much more selective for the H_2S. This means that it is much more difficult to remove the CO_2 than the H_2S from the syngas. The H_2S removal system is much too small to also remove a large portion of the CO_2. It must be able to be scaled up considerably, with much additional equipment required. The CO_2 removal system requires a significant amount of high pressure steam to strip (remove) the CO_2 from the solvent, so that it can be concentrated. Therefore, the steam turbine must be designed from day one with steam extractions at the right temperatures and pressures for CO_2 stripping.

Significant additional power is required for the CO_2 removal system to operate. With the extraction of steam noted previously, and the increased internal power use, the IGCC plant's net output falls considerably, and this deficit must be made up by other sources of generation.

Once the CO_2 is removed from the syngas, a hydrogen-rich syngas stream remains. While gas turbines have the ability to burn syngas and other fuels that contain some hydrogen, gas turbines for the combustion of concentrated hydrogen streams are not yet commercially available at large scale. Gas turbine manufacturers are doing R&D on their products to see how high a concentration of hydrogen can be safely combusted (the burning profiles of natural gas, hydrogen and syngas are all very different, and the burners must be specifically designed to provide for safe, controlled combustion, especially with hydrogen). Large, commercially-available gas turbines for hydrogen-rich syngas are not expected until 2014.

Therefore, IGCC is not inherently CO_2 capture ready without significant additions, modifications and impacts to its efficiency and output. I have heard many people apply the term "CO_2 capture ready" to IGCC without really understanding what is involved, both technically and financially, to implement these significant changes. Just because people call it CO_2 capture ready does not mean that it is.

Q. Have CO_2 capture technologies been applied to IGCC?

A. Yes, but only on a test basis.

Q. Are EPRI and the DOE funding R&D on CO_2 capture technologies?

A. Yes. A significant amount of design development is underway, in order to qualify and quantify the modifications described previously. CO_2 capture for IGCC is not yet a commercially available technology. 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. This is primarily because the CO_2 must be removed from the flue gas after combustion. Since air is used in combustion, the flue gas stream from a PC unit has a high concentration of nitrogen (from the air), and the CO_2 is at a very low concentration. It is much more difficult to remove CO_2 from a weak stream than a concentrated stream. The CO_2 capture system must be much larger, more expensive and more energy intensive. EPRI and the DOE are funding R&D for CO_2 capture for both PC and IGCC.

Q. Would inclusion of CO_2 capture technology reduce output at the plant?

A. Yes. As I noted previously, a considerable amount of steam must be extracted from the steam turbine for the CO_2 stripping process. This steam would otherwise have been used for power generation. In addition, the CO_2 capture system has large internal power requirements for pumps and other equipment. All of these reduce the plant's net output in a significant way. A recent study by the EPA shows that the addition of a CO_2 capture system would reduce the output of an IGCC plant by 14% and a SCPC plant by 28%. The result of this is that the plants would become very inefficient, and would be unable to meet their intended load requirements.

Another option would be to size the plant to be much larger in the beginning, so that the net output, after all of the steam extraction and additional internal power ruse, results in the required net output. Of course, this would require the expenditure of a significant additional capital cost to build the plant.

Q. Would CO_2 capture technology raise the cost of electricity?

A. Yes. It would. The equipment required for CO_2 capture is both extensive and expensive. The plant would be more expensive, and the cost of electricity, which would include a component to account for this additional capital expenditure, would be higher.

Q. Can you say that IGCC is "CO_2 capture ready" today?

A. It is not. Once the R&D is completed over the next decade, as described previously, IGCC is expected to be CO_2 capture ready.

Q. Is IGCC currently effective at removing CO_2 and then providing an appropriate storage location?

A. No. It is not. There is no experience with the capture and sequestration of CO_2 from the four operating IGCC plants. To date, only pilot testing has been done on IGCC plants for CO_2 capture. No sequestration of the CO_2 captured from those tests has occurred.

Q. Are you aware of any other power companies that have investigated the use of IGCC?

A. Yes. I am aware of many power companies that have investigated, or are presently investigating, the use of IGCC.

Q. Has AEP investigated the use of IGCC?

A. Yes. It has investigated the use of IGCC.

Q. Who is AEP and what did it conclude about the use of IGCC?

A. AEP is the American Electric Power Corporation. It is the largest generator of electric power in the U.S. AEP conducted a major study of IGCC technology. The conclusions of that study, as presented by Mr. Michael Mudd of AEP, were as follows:

- IGCC technology is not yet mature;
- IGCC efficiency is worse than advertised;
- IGCC costs are higher than advertised;

- It is difficult to get a fixed price and guarantees for an IGCC facility;
- IGCC startup is long and complicated; and
- More R&D is needed for IGCC to be proven for commercial use.

Initially, AEP found that the IGCC suppliers were not able to provide a "wrap" of guarantees. As business alliances were formed among gasification technology suppliers, power block suppliers, and engineering firms, AEP eventually felt comfortable in expecting to obtain reasonable guarantees, and proceeded with the Front End Engineering and Design ("FEED") phase for a 600 MW net IGCC reference plant.

Its IGCC plant will be developed in either Ohio or West Virginia, depending on which state will allow it to recover the additional costs of building an IGCC plant instead of an SCPC plant. This is a critical part of making the project financially feasible for AEP. Once this initial design phase is completed, AEP will also have a more accurate cost estimate for the plant, and will be able to determine whether to continue with the project. AEP was planning for the capital cost premium of IGCC over PC to be no greater than 20%.

In late December, 2006, AEP noted that its FEED study showed that the cost would exceed this 20% premium. Because of that, AEP has instructed their technology supplier team to re-evaluate and modify the design to find ways to reduce the cost to meet this goal. It will likely be another six months before this re-design and revision of the cost estimate are completed. AEP will need the new cost estimate before it goes before the public utility commission to request approval for the costs of detailed design and construction.

In addition to going forward with this IGCC project, AEP has continued to rely on SCPC technology. In August of 2006, AEP announced the development of a 600 MW USCPC plant to be sited near Fulton, Arkansas, scheduled for operation in the summer of 2011. In announcing this new PC plant, the company's president noted that "we believe that a coal- or lignite-fueled plant is the best choice for new base load generation to economically fuel the future growth of the economies in our region, allow us to remain a low-cost provider, and prevent over-reliance on natural gas for electricity generation as domestic national gas supplies are diminishing."

Q. Overall, how would you compare the plant efficiency for IGCC technology to the proposed FPL plant?

A. The "promise" of IGCC technology included much higher efficiencies than PC units. In practice, neither Polk Power Station nor Wabash River Generating Station has met its efficiency goals. It was expected that through process and technology improvement, this next generation of IGCC plants would meet the goal of 40% efficiency. Unfortunately, it does not look like that will happen. Of all of the coal-based IGCC plants being planned, not one has a planned efficiency of over 38%. The highest efficiency values, according to information provided by the power companies in their public documents and especially in their air permit applications, will be ERORA Corporation's planned IGCC plants in Kentucky and Illinois, with efficiencies of 36.8%. These efficiency values are typically provided in the industry at "new and clean" conditions; performance typically degrades over time as equipment ages and wears. Earlier this year, Tampa Electric Company announced that it was planning to build a second IGCC plant at Polk Power Station. Polk Unit #6 will be a 600 MW (net) plant. Its efficiency, as noted in Tampa Electric Company's Ten Year Site Plan submittal, is planned to be only 36.6%.

FGPP is being designed for an efficiency of 38.8%, which is higher than that for the next generation of large, commercial-scale, coal-based IGCC power plants.

Q. How would you compare the emissions between an IGCC plant and the proposed FPL plant?

A. They are very similar for many of the primary pollutants.

Q. How would you compare the reliability between an IGCC plant and the proposed FPL plant?

A. FGPP is being designed for an availability of 92%. This is much higher than what the four existing IGCC plants have been able to achieve. As I noted previously, design improvements and the addition of spare equipment are expected to provide for 85-90% availability on the planned IGCC units. It is possible that the availability of IGCC and SCPC could be comparable, but we will not know what IGCC availability will be for another six to eight years.

Q. How would you compare the cost certainty between an IGCC plant and the proposed FPL plant?

A. At the present time, the cost of IGCC is not known in anywhere near the detail or accuracy as that of PC units. Since there are hundreds of SCPC units around the world, these costs are much more certain. Once one of the companies planning an IGCC plant actually signs a contract for the purchase and development of its IGCC plant, the industry will have a much better idea of what IGCC will really cost. At this time, the range for IGCC cost is very wide and uncertain. It has also been difficult to obtain guarantees or risk sharing with the IGCC technology suppliers at a reasonable cost.

Q. How would you compare the maturity of the technology between an IGCC plant and the proposed FPL plant?

A. USCPC technology is proven worldwide on a large, commercial scale. IGCC is still in development, and is not yet mature. However, in six to eight years, we will have much more experience with IGCC technology once the units being planned actually go into operation.

Q. In your professional opinion, would you recommend the use of IGCC technology for this proposed power plant?

A. Based on the requirement for a power generation technology that can provide 1,960 MW net in the 2012 through 2014 time period, high efficiency, low cost, high cost certainty, high reliability, and low emissions, I would not recommend IGCC technology for FGPP.

Q. In your professional opinion, in terms of reliability, cost-effectiveness, emissions, and commercial availability, do you recommend the technology being proposed by FPL for the proposed power plant?

A. Yes. I recommend the use of USCPC technology for FGPP. It meets the requirement for a power generation technology that can provide 1,960 MW net in the 2012 through 2014 time period, high efficiency, low cost, high cost certainty, high reliability, and low emissions.

Q. Please summarize your testimony.

A. After comparing the USCPC technology proposed for use at the FGPP with IGCC technology, I have found that USCPC technology is more technologically mature, more efficient, and higher in availability than IGCC technology. It also provides for a similar environmental emission profile as IGCC technology, and more cost certainty than IGCC. I conclude that the selection of USCPC technology for FGPP would be a prudent decision by FPL.

Q. Does this conclude your direct testimony?

A. Yes. It does.

BY MR. ANDERSON:

Q. Do you have a summary of your testimony, Mr. Jenkins?

A. Yes, I do.

Q. Will you please provide your summary at this time?

A. Yes, thank you.

Good afternoon, Chairman Edgar and Commissioners. My name is Stephen Jenkins, and I'm Vice President of Gasification Services for the engineering firm CH2M Hill. My work deals directly with the permitting and design of integrated gasification combined cycle or IGCC power plants nationwide. When I worked at Tampa Electric Company, I was the deputy project manager for the Polk Power Station IGCC unit, which is one of the two IGCC plants in the United States.

My testimony shows that FPL's choice of the ultra-supercritical pulverized coal technology is the first choice for Glades Power Park and is a prudent one. In fact, it's a better choice than IGCC, which is still a developing technology.

Some of my main points are as follows: There are only four coal-based IGCC power plants in the entire world. There are over 500 supercritical pulverized coal power plants, with 17 of them being ultra-supercritical, that using the official DOE designation and definition that Mr. Hicks already told you about.

Supercritical technology has been in commercial use worldwide for about 50 years, while IGCC has an operating history of only about 12 years.

Ultra-supercritical units have been proven in service at sizes over 1,000 megawatts, while IGCC has been demonstrated at only about 250 megawatts in size. Larger units mean lower relative costs and higher efficiency. While there are 600-megawatt IGCC plants now being designed, they won't go into operation and be proven for about another six years.

Supercritical units have a higher reliability than IGCC. For example, the Glades Power Park units will be designed for an availability of about 92 percent. None of the four coal-based IGCC plants in the world have met their target availability of only 85 percent. Now, while we are designing a lot of enhancements into IGCC to improve availability, again, those changes in those units won't go into service for years to come and won't be proven for about six years.

Supercritical technology is actually more efficient than IGCC. That's not what we expected in the IGCC industry. Not one of the planned coal-based IGCC power plants that we've been talking about this morning will be as efficient as the units at Glades Power Park, not one of them. Higher efficiency means using less coal to produce the same power, the same kilowatt-hours of electricity. That's what Glades Power Park will do in comparison to IGCC units. Using less coal means lower emissions and less CO_2.

We also expected that the capital cost premium for IGCC over the supercritical pulverized coal units would be only about 20 percent. But based on some recent detailed cost estimates and regulatory filings in other states, we now know that number to be closer to 35 to 40 percent more for IGCC than for the supercritical pulverized coal. But we really won't know what IGCC costs until one utility is the first to actually purchase and contract for one of the new 600-megawatt units, which will happen late this year, we think.

Another issue is CO_2. While some believe that IGCC inherently captures the CO_2 from the process, it does not. It takes a significant amount of very capital intensive equipment to do that. In fact, CO_2 capture is not proven at any scale on IGCC worldwide. However, we do expect that this CO_2 capture technology will become commercially available for both IGCC and supercritical pulverized coal in the future at a similar cost. And that's an important note. That's one more reason why it's prudent to select the ultra-supercritical pulverized coal technology.

Overall, ultra-supercritical pulverized coal technology is more commercially proven, higher in efficiency, has a higher availability, and lower in cost than IGCC, and has the capability for CO_2 capture. That's why FPL's selection of the ultra-supercritical pulverized coal technology is the right choice for the Glades Power Park units.

Thank you.

MR. ANDERSON: Mr. Jenkins is available for cross-examination.

CHAIRMAN EDGAR: Okay. Ms. Perdue.

MS. PERDUE: No.

CHAIRMAN EDGAR: No questions. Thank you.

Mr. Beck.

MR. BECK: Thank you, Madam Chairman.

CROSS-EXAMINATION

BY MR. BECK:

Q. Good afternoon, Mr. Jenkins.

A. Good afternoon.

Q. Would you turn to page 26 of your prefiled testimony, please.

A. Yes.

Q. At lines 17 through 18, you state that applying CO_2 capture to a PC plant is presently much more difficult and expensive than for an IGCC plant. Do you see that?

A. Yes, I do.

Q. And I think in your summary you just stated that you thought that carbon capture for an ultra-supercritical pulverized coal plant and IGCC would have a similar cost in the future; is that right?

A. Yes, I did.

Q. Okay. Were you here during the redirect examination of Mr. Hicks just before yourself?

A. Oh, yes, I was.

Q. And did you understand him to say that he thought carbon capture would be cheaper for an ultra-supercritical pulverized coal plant than it would be for an IGCC plant?

A. Yes.

Q. What's your understanding of --

A. If you look at line 18, the fourth word is "presently," and that is based on the research and development that has been done to date on CO_2 capture technologies and very many studies that have been done. As Mr. Hicks explained in some of his answers, there are now more and more research and development projects being done for CO_2 capture on pulverized coal technologies. Obviously, the market for that kind of technology is with pulverized coal, not IGCC. There are only four coal-based IGCC plants in the world. There are hundreds and thousands of pulverized coal plants. That's why the boiler companies are doing so much more research and development to lower the cost and be able to apply this technology to PC technology, while the IGCC industry is doing some additional CO_2 capture R&D.

So the point is, the present types of data and studies that have been available have shown that PC would be more expensive. That's why I said presently in there. However, as Mr. Hicks specifically noted, the latest cost estimates and the projections from -- like on the chilled ammonia system will clearly show that overall, the costs for CO_2 capture are going to be fairly equivalent for both technologies. Fortunately, we'll be able to apply the CO_2 capture technology to either one.

Q. So do you agree with Mr. Hicks or disagree that pulverized coal will be less expensive for carbon capture than for IGCC?

A. It depends on which coal you're using and what -- the size of the units and a few other issues there.

Q. Well, how about the Glades plant?

A. It would be -- PC would be less expensive.

Q. And why would it be less expensive for the Glades plant as compared to other types of ultra-supercritical pulverized coal plants?

A. I didn't say that it would be more expensive on others.

Q. Okay. What's your basis for thinking it would be less?

A. Oh. Well, for example, there was a recent study done by the Electric Power Research Institute for City Public Service of San Antonio looking at PC and IGCC with and without CO_2 capture. And this is a publicly available report and has been discussed at length in many different fora across the industry and in the regulatory proceedings. It is one of the latest and most up to date studies that shows what the best costs are for PC and IGCC with and without CO_2 capture. The bottom line result of that study shows that when you add CO_2 capture to both PC and IGCC, that the pulverized coal unit was actually less expensive. That is the latest data that is being used and accepted in the industry. And that's a public report, should you like to see that, at EPRI.com.

Q. Okay. So you think that the economics are going to change, IGCC versus pulverized coal plants, for carbon capture, as I take it. You know, from your testimony, you said it's presently much more difficult and expensive for a PC plant than it is for IGCC; right?

A. Yes, based on present studies. I mean, nobody is doing this, so we really can't say, "Here's a system, and it's removing CO_2 from a PC plant, and this is the cost." This was based on studies, and now we have, since the EPRI report came out, even better numbers and more up-to-date numbers.

Q. What's the date of the EPRI report that you're referring to?

A. It was just a few months ago that EPRI released this. In fact, I was with City Public Service of San Antonio earlier this week going over the report with them.

Q. Over what time frame do you see the economics change from what you say is presently the economics to what you see it changing to in the future?

A. Daily. There's so much work being done with so many R&D projects looking at pulverized coal, because as I said, with hundreds of thousands of PC plants around the world, whenever time comes that we have to do CO_2 capture, that's the market. And the boiler manufacturers want to be here in five years, ten years, 15 years, so they will find the technology and make it work so that it will be cost-effective.

Another example is in the EPRI Journal, Electric Power Research Institute, which does the R&D for the utility industry. In last month's EPRI Journal, they had a very good and detailed article called "The Challenge of Carbon Capture." And one of the specific statements in there was that with the enhancements being made to both IGCC and PC -- and I'm paraphrasing it, and I could get you that article if you would like -- we expect the cost of electricity with CO_2 capture on both IGCC and PC to be the same number. And that is the latest data out.

Q. Do you have an opinion on whether at some time during the life of the Glades Power Plant, do you have an opinion on whether they would put in carbon capture or not, or whether that would be --

A. I do not.

Q. Could you turn to page 27 of your testimony?

A. Yes.

Q. On lines 8 through 10, you say, "A recent study by the EPA shows that the addition of a CO_2 capture system would reduce the output of an IGCC plant by 14 percent and an SCPC plant by 28 percent." Do you see that?

A. Yes, I do.

Q. Okay. What's the date of -- you said a recent study. What's the date of that study?

A. That, I believe, was the EPA environmental footprints study that was referenced previously when Mr. Hicks was here.

Q. And do you know about the time frame when that was issued?

A. That came out in June of 2006.

Q. Do you see those numbers changing over time, the 14 and 28 percent that you refer to in your testimony?

A. Yes, I do, fortunately.

Q. And how do you see that going over time?

A. What the Department of Energy has recently said is, they want to be able to get CO_2 capture from PC and IGCC to the point where the units, the base units are more efficient, and then when you add the CO_2 capture, I think by 2020 was the number, or maybe sooner than that, that the impact on efficiency would be no impact on both IGCC and PC. That's the goal of their CO_2 capture program, so that we won't have these huge impacts that we're seeing right now.

MR. BECK: Thank you, Mr. Jenkins. That's all I have.

CHAIRMAN EDGAR: Mr. Guest, do you have

questions.

MR. GUEST: Yes. Thank you, Madam Chair, Madam Chairwoman.

CROSS-EXAMINATION

BY MR. GUEST:

Q. Good afternoon, Mr. Jenkins.

A. Good afternoon.

Q. In the course of your work at CH2M Hill, you've had the opportunity to do presentations about IGCC plants, have you not?

A. Yes, I have.

Q. Do you have them with you?

A. No, I do not.

Q. Well, let me refer you first to a presentation that you made at the Gasification Technology Council workshop on March 14, 2007. Do you remember that?

A. Oh, yes, very well.

Q. That was just about what? Six weeks ago?

A. About that, yes.

Q. Five weeks ago?

A. Yes.

Q. And it was called IGCC 101?

A. Yes.

Q. Well, I have that sheet. Maybe I'll pass that around with the second page that we turn and use with this.

Do you remember saying that it had advantages?

A. That what had advantages?

Q. IGCC has advantages.

A. Yes.

Q. And what you meant by advantages was advantages over pulverized coal, didn't you?

A. And other technologies, including pulverized coal.

Q. And the advantages included that it had a wide range of feedstocks; is that right?

A. Yes, if specifically designed for them. One unit by itself does not necessarily design for all feedstocks or a wide variety. As Mr. Hicks stated earlier today, just like pulverized coal units, you have to design the IGCC unit for the specific feedstock.

Q. So you worked on the TECO unit?

A. Yes, I did.

Q. And when you say you have to design it for a specific feedstock, does that mean that you would run it only with coal or only with coke, petcoke?

A. At the time we designed it, our plan was that it was designed only for coal. In fact, we designed it for Pittsburgh No. 8 seam coal from northern West Virginia as the performance coal, along with an Illinois

No. 6 coal, because it was slightly higher in sulfur and was available at low cost to Tampa Electric on its river and barge system that would bring the coal to the station. So there were really two, one design coal and one performance coal.

Q. Well, but that plant runs 60 percent petcoke.

A. When the petcoke as an opportunity fuel is lower in cost than coal, Tampa Electric does use it. There are other costs, environmental and technical issues that come along with petcoke, such that there are times when Tampa Electric does not use 60 percent petcoke, and particularly because it was neither designed or permitted to use petcoke.

Q. Now, turning to the cost issue, you're aware, are you not, that FPL has submitted in this proceeding cost projections on petcoke versus coal?

A. I have heard that, yes.

Q. And the TECO plant can use 100 percent coal?

A. It was designed to use 100 percent coal.

Q. Or 100 percent petcoke?

A. It was not designed to use 100 percent petcoke.

Q. Can it? Can it use 100 percent petcoke?

A. I do not know that it can. It was not designed to do so. And as I noted, since the environmental permits do not allow for 100 percent petcoke, the design of the gasification system does not allow for 100 percent petcoke. And the sulfur removal system that allows them to meet their environmental permitting conditions does not allow for 100 percent petcoke.

Q. So it runs a maximum of 60 percent?

A. I know that it has run before at 60 percent. I'm not sure what the maximum number is.

Q. So it could run at 60 percent, 50 percent, 40, 30, 20, 10, or zero?

A. It has done different blends of petcoke with different coals. And the reason that they do that is again for cost purposes. But there are times -- because of the nature of the gasifier design, you just don't put any blend in there. You have to blend the petcoke with a coal that will still end up with a sulfur content that will meet their environmental permits, ash characteristics that will work right in the gasifier, and many other issues that go along with the basic design. And that's because the plant was not designed to use petcoke. Every time they want to change a blend, they do testing. They have a computer simulation that shows what that blend will look like, and then they do a small test feedstock use of that before they go into any major change.

Q. Okay. Turning now to your testimony a moment ago that carbon dioxide capture was not actually proven on any scale.

A. On IGCC. That's what I said in my summary, that's correct.

Q. Okay. And I'm working out of your PowerPoint presentation of five weeks ago.

A. Yes.

Q. And I want to ask you, did you have anything in your PowerPoint presentation about an IGCC plant that had -- a plant that had captured carbon dioxide?

A. No, I did not.

Q. How about a gasification plant?

A. Yes, there is a gasification plant, but there are no IGCC plants that do any capture of CO_2. That's a big distinction. A gasification is a small part of an overall IGCC plant. Gasification plants are typically used to make chemicals, natural gas. Kodak film is made from syngas. But they don't make power. IGCC is when you match and integrate the gasification process from the chemical industry with a combined cycle power plant from the power industry, and you do all the engineering to make them work together for power generation. That's a big difference.

Q. Well, you included a description of a plant like this as the sixteenth page of what you described as IGCC 101.

A. Yes, I did. And the reason I did that, again, is that I am often asked to do this IGCC 101. In fact, prior to doing that workshop, I was asked by Chairman Binz of the Colorado Public Utilities Commission to give them my IGCC presentation so that they could better understand what IGCC is, particularly because Excel Energy, the local utility in Denver, has proposed an IGCC unit. And they found out that I was going to be in town, and Chairman Binz's assistant called me and said, "Would you be willing to come over in the afternoon and give the three Commissioners your IGCC 101 that we've heard so much about." And I did that. And then at the workshop, since it was also in Denver, the one that Mr. Guest is talking about, all three Commissioners came back and brought their staff to hear it again.

Now, the reason I discuss that plant, that gasification plant, is so people have a good understanding that an IGCC plant is made up of a gasification plant and a combined cycle plant. So whatever slide number that was, that was the piece of what a gasification plant is, looks like, and does. Then I talk about what combined cycle power generation is, and then I talk about how you put them all together and about how important that "I" of integrated gasification combined cycle is that keeps engineers like me up at night trying to figure out how to make them work better. That was the reason for including that specific plant.

Q. Well, when you talked about that plant, it had another feature of interest besides that it was gasification, didn't it, the plant at Dakota?

A. Yes. It makes synthetic natural gas from coal.

Q. What else does it do that's of interest to IGCC?

A. What?

Q. Does it have any other feature that's of interest to IGCC?

A. I'm not sure what you're getting at.

Q. Well, that plant that you have on the sixteenth page of your IGCC 101 presentation from five weeks ago also says that it captures carbon dioxide, doesn't it?

A. Yes, it does. It captures a part of the carbon dioxide that's produced. When you gasify coal and turn it into synthetic natural gas -- and that plant does that, and they put it into the local pipeline, a good part of the carbon that was in the coal is converted to carbon dioxide. They used to just vent it, because that was the thing to do. I mean, that was part of the original design and the process back in 1978.

What they've done since then, and it is an interesting aspect of that plant, about 200 miles away from this plant -- and this plant is in Beulah, North Dakota, which is a great place to be in the summer, but not in the winter, I found out. EnCana and Apache Canada have oil fields in southern Saskatchewan. They have found that those plants -- the oil production rate has fallen off considerably, and they have learned through a lot of R&D that if you use pressurized carbon dioxide and you put it down several thousand feet, it mixes with the oil and can help you get more oil out.

So they did a deal with Great Plains and Dakota Gasification that operates the plant. And what they did is, they paid Great Plains to install a more enhanced CO_2 removal system, three huge 20,000-horsepower compressors, and they compress the CO_2 that they get, not all of it, but a part of it -- the rest is still vented -- and they pipe that 205 miles to these wells in Saskatchewan, and it helps EnCana to get a little bit more oil out of those fields. And someday they will tail off again. That's the term that we talked about called enhanced oil recovery, and that is a potential use for CO_2. That's what happens there.

Q. So at that gasification plant, they're able to sequester some CO_2?

A. That's not correct.

Q. Well, how do they -- I'm sorry. How do they get the CO_2 sequestered if they don't sequester it?

A. The intent of enhanced oil recovery is not to sequester the CO_2. There you want to use as little CO_2 as possible, because they are paying for it.

Q. I'm sorry. I garbled the question is what happened there. What I meant to ask instead of what I did ask was that they had succeeded here at the Dakota plant in capturing CO_2 and then putting it to use to enhance oil recovery 200 miles away. That was my only question.

A. Yes, because they're being paid a lot of money to do it.

Q. Okay. And then we have the Coffeyville Resources plant that you also included in your IGCC 101.

A. Yes, I did.

Q. Could you explain that for us, please?

A. Which part of it?

Q. Well, it operates on petcoke.

A. Yes, it does.

Q. And it produces syngas?

A. Yes.

Q. And it removes carbon dioxide?

A. A portion of the carbon dioxide. And they do that for a very good reason. They are paid to do it. They remove a little over 50 percent of the carbon dioxide from that process. The Coffeyville Resources plant takes petcoke, and they gasify it. And the reason they do that is because they are a fertilizer plant, and to make fertilizer, you need ammonia. The only way to make ammonia is from hydrogen. The only way to make hydrogen has been from using natural gas.

When natural gas prices went up significantly, as we have all seen, their cost of making hydrogen and ammonia made them uneconomic, so they installed this petcoke gasification plant. They make the hydrogen from the syngas. It is a mixture of carbon monoxide and hydrogen. And now they are very economic.

As part of that, they also make a product called urea, which is used in making fertilizer. And urea has a couple of carbon dioxide molecules in there as part of the urea, and you do that by reacting ammonia with carbon dioxide. And I hate to get into the chemical reactions.

But to them, they are paid a lot of money in the market for the urea, so it is economically an advantage for them to capture as much CO_2 as they can. They react it with the ammonia, and they make urea, and they sell it for a lot of money because they are so economic now at that Coffeyville Resources plant. But they don't capture all the CO_2, and the part that they do capture, it's only because they get paid to do it, a lot.

Q. And actually, the part that they capture is vented; is that right?

A. The part that they do not capture is vented, just like it was years ago.

Q. Now, I think that the point of this presentation up until now was to show that the gasification component of an IGCC plant is really a chemical plant process as contrasted to burning coal and heating a boiler like you do in an old steam locomotive. Isn't that the point of that part of your presentation?

A. Yes. That part of the presentation was to explain to people what the gasification portion of an IGCC plant is, and the best way to do that, I have found, is to show people what gasification is.

Q. Right. And so there really is a huge difference here, in that an IGCC plant is really a chemical plant that produces a gas that drives a turbine and then captures the heat after the turbine. Isn't that really what's going on here?

A. That's why we had so many chemical engineers working on Polk Power Station.

Q. Right.

A. Because this is a chemical process.

Q. Yes. It's a chemical plant that produces a gas that you burn in a turbine.

A. Yes.

Q. Isn't that the concept?

A. Yes, gasification plus combined cycle, integrate them, IGCC.

Q. All right. And there are a lot of chemical gasification plants out there?

A. Yes.

Q. 117?

A. Yes, 117 plants, just under 400 gasifiers around the world, but only four coal-based IGCC plants. And that's a big difference.

Q. Okay. We'll deal with these things one at a time. So the gasification component, that's no surprise. That's not a new technology, and it's in wide use around the world?

A. Gasification is in wide use around the world, yes.

Q. And they gasify coal, petcoke, refinery wastes, and a wide variety of other things?

A. Yes. Most use refinery wastes, asphalts, tars, things like that, because they have been sited at adjacent refineries for the purpose of using the refinery wastes and gasifying them and making hydrogen for use in the refinery.

Q. You had in your presentation five weeks ago a list of the benefits of IGCC.

A. Yes, the potential benefits of IGCC are part of that IGCC 101.

Q. And it lists benefit of IGCC, and the first item that you listed -- well, wait a minute. Just to be clear, you didn't say potential. Your presentation says benefits. It doesn't say potential benefits.

A. Well, what I said at that -- that's what the presentation says.

Q. Okay. That's your words, but not the PowerPoint.

A. Sometimes I put the word "potential" in there. You know, it's just when I do the presentation. It just depends. I don't say exactly the same thing every time on that presentation. I've given that probably 30 times to different groups, different commissions, different environmental agencies in Florida, Texas, Colorado.

Q. So the first advantage that you listed in your PowerPoint from five weeks ago was that you could take advantage of low cost coal or petcoke?

A. If so designed for it, and I explain that when I get to that slide.

Q. And then you say that coal costs -- or you say coal at $2 per million Btu, petcoke at half that.

A. As an example.

Q. And that corresponds with the exhibit that's in this case about the estimated future costs of petcoke versus Appalachian coal.

A. I have not looked at that.

Q. Another advantage of IGCC that you had in your PowerPoint was that it took advantage of high efficiency of combined cycle power block. What does that mean?

A. The combined cycle power plant is an efficient way of using natural gas to make electricity. And when you use syngas in the integrated gasification combined cycle mode, you're taking advantage of the combined cycle power plant. That's what it means, just like you would take advantage of a high efficiency boiler and mating that with a high efficiency steam turbine generator.

Q. And the then third item was that you say environmental profile, under benefits, air emissions, liquid discharges, and solid by-products.

A. Yes.

Q. So the environmental -- the benefit of IGCC, one of the three listed here, does that mean lower air emissions?

A. In some cases, yes, in some cases, no.

Q. And then the liquid discharge advantage, what's that?

A. IGCC plants can be, but are not always -- well, we only have four to go by right now, and some have this, and some don't, where instead of having a liquid discharge, it goes through like a distillation system, and you end up with a solid cake, and that allows you to recycle as much water as you can back into the system, the same way that you do with the gypsum from a flue gas desulfurization system in a supercritical pulverized coal unit. It comes out as a slurry, you put it through vacuum filters, and you have this solid cake gypsum which, as Mr. Hicks talked about, you can sell for making wallboard and cement, and all that water goes back into the process. It's just a method of being smarter with water use.

Q. Okay. Use less water? Is that it?

A. Yes, it use less water, discharges less.

Q. Okay. And then another piece of the environmental profile that's an advantage is solid by-products.

A. Yes.

Q. Does that mean that you can sell -- if you do it right, you could sell the -- instead of discharging sulfur dioxide into the air or capturing it in a scrubber, that you actually can turn it into powdered sulfur and sell it? Is that the concept?

A. It depends on your local market. Some units may make -- actually, you make a molten sulfur, not a powdered sulfur, and that is a commodity, a chemical, and can be used in different processes, or like we did at Polk Power station, the sulfur was recovered as sulfuric acid. That is one -- actually, that's not what I meant by solid by-products. What I meant by solid by-products was the slag.

Q. Well, I'm glad you told us about the sulfur. Let me ask you a follow-up quick question about the sulfur. When I see that -- when I'm out on Gaines Street and I see that rail car go by that says sulfur on it, is that what's in it? It's liquid sulfur?

A. I've not seen that tank car.

Q. But do you see tank cars with liquid sulfur going by on railways? Is that --

A. I try not to hang out in those places. I don't know.

Q. There's something about the sulfur you don't like?

A. No, it's a good chemical, but I just -- I've not been at a rail crossing at the time to see a tank car come by.

Q. All right. Returning to your point, which was the solid by-product to which you were referring, that was -- I think you said slag. Is that what it was?

A. Yes, yes.

Q. Can you give us a mouthful of what slag is?

A. Yes. The ash that is inherently and naturally in the coal, whether it's being used in a gasifier or in a pulverized coal unit, because of the high temperatures, it typically -- that ash melts, and it's molten. It falls into a water bath, it is quench-cooled, and it turns into a black, glassy material that the industry calls slag. It's crushed, it's pumped out, it's screened, and if it meets certain properties, it can be used for things like making cement, making sand blasting grit, roofing tiles -- when you see the shingles that have that gritty stuff, that's typically boiler slag -- and other types of uses. And you do with either PC units -- pulverized coal units or gasifiers make almost the same identical slag.

Q. Oh, it looks the same?

A. Not only does it look the same, but it has the same chemical characteristics.

Q. Okay. All right. Also in your PowerPoint, you had some illustrations of four coal-based IGCC plants.

A. Yes.

Q. Nuon in the Netherlands, which runs on coal and biomass?

A. Well, it's actually chicken litter. It's not what I would call biomass, but it has its own inherent issues, being chicken litter.

Q. What fraction of chicken litter do you run in this plant?

A. In Nuon?

Q. Yes.

A. I can't remember what the number was. The Netherlands government paid them to have -- Nuon to add in a special feeding system, because as you can imagine, feeding coal is very different from feeding chicken litter, so to do that, they had to modify their system, which again is the issue of if you haven't designed for it up front, you may have to make some very big changes later.

Q. Okay. So we --

A. That's the reality of using chicken litter.
Q. Then you also talk about the Wabash River one in Indiana.
A. Yes.
Q. And that runs on coal and coke. Do you mean -- by coke, do you mean petcoke?
A. Petroleum coke, petcoke, yes.
Q. And then you've got the TECO one, which I think you've talked about already, at Mulberry. That's petcoke and coal.
A. At times.
Q. And then you also have -- do you know how to pronounce that place in Spain?
A. Puertollano, P-u-e-r-t-o, like Puerto Rico, Puerto, with then l-l-a-n-o, Puertollano.
Q. Puertollano. And that's coal and coke, coal and coke, petcoke?
A. Yes, it is. It depends again for them on cost too. It was not designed for petcoke. It was designed for coal.
Q. And then we also have one in the Czech Republic?
A. Yes. That's not exactly an IGCC unit. That was put in to make what the industry calls town gas, where you gasify coal and you pipe it around. That's

what we used to see before there were natural gas pipelines. People all over the world made town gas, and that's what lit the old street lamps when you see the old movies in England. There was no natural gas distribution line that went to that street lamp. It was town gas that was made locally. And they converted those units several years ago to make a little bit more of that town gas, and when it's not being used for heating, cooking, and lighting in the small Czech town, they burn it in some combustion turbines, but it is not an IGCC unit.

Q. I see. Are there two in China? Am I right that there's two in China that have just come on?

A. I think those are proposed IGCC plants. They are not in operation. There are many gasification plants in China, but not IGCC.

Q. Do you know the one at Yankuang?

A. I don't know that one. I have read about it and some of its plans.

Q. It makes methanol too, besides power?

A. Yes, that is one of the ones in the world that is used for making chemicals, not electricity, as a primary product. They actually use steam produced from the methanol process to drive a steam turbine, not syngas from the gasifier to drive gas turbines. It is not an IGCC unit. It is a chemical plant. They only use the waste heat to make power. As I noted, there are only four coal-based IGCC plants in the world.

Q. But there's one proposed for Polk County?

A. There are only four today. I go back to that word "presently."

Q. Okay. Right now?

A. Right now.

Q. And how many are proposed?

A. There have been so many proposed, and it changes every day. I actually do some work for the Gasification Technologies Council and EPRI in trying to keep track of all the ones that are proposed, and every day we add one, and every day we take one off, because for whatever financial reasons or whatever, they go away. I --

Q. Which one did you take off yesterday?

A. It was a confidential project that our firm was working on.

Q. Okay. Which one did you add yesterday?

A. There was one announced in the -- I believe it was in the Netherlands. It was for actually more gasification than IGCC, using Shell technology.

Q. Can you give me the name of an IGCC plant that was first proposed last week?

A. Yes. Well, TXU named two potential sites for putting in IGCC about a week ago. They didn't give it a name. They don't have a technology. They haven't selected what kind of coal it is. But sometimes that's all that proposed means, somebody has mentioned it, and they haven't done any engineering at all.

Q. Okay. While we look around at that issue, I would just like to just touch base on a few things about the TECO Mulberry plant. I've got a photograph of that I would like to distribute, which will be Exhibit Number 180, 179.

CHAIRMAN EDGAR: 179.

MR. GUEST: 179.

CHAIRMAN EDGAR: Photo, TECO Polk Power Station?

MR. GUEST: Yes. Thank you. Well, IGCC power station. Whatever. I'm sorry. I shouldn't do this.

(Exhibit 179 marked for identification.)

BY MR. GUEST:

Q. Okay. Can you describe where the stack that the exhaust gases come out of -- where is this? Is that that black thing in the foreground?

A. No. In the foreground is the syngas flare. That is part of the chemical process. When you start up and shut down, that flares.

Q. Then there's a little thing that's got some steam coming out of it in the sort of center left.

A. Yes. That's part of the sulfuric acid plant and auxiliary boiler.

Q. They use the sulfuric acid at this plant to sell to the phosphate -- fertilizer companies to process the phosphate?

A. At times. It depend on the price. At other times they sell it to municipalities for use in water treatment.

Q. Okay. So which one of these stacks is the sort of smokestack here?

A. What do you mean by smokestack?

Q. Well, where the emissions that we all are concerned about come out of.

A. Most of the emissions would come from the heat -- outside of the heat recovery steam generator, the stack which is -- I think it's about 80 or 120 feet tall. It's on the upper left side of the picture. But there's a -- you can see a little stack that kind of has a twisty thing on the top of it. That's the stack from the sulfuric acid plant. Just to the right of that in the background is the actual stack from the combined cycle plant.

Q. This plant appears to be in operation?

A. It looks to me -- and I think I was in the helicopter when we took this picture, and we were allowed to do that because the plant was not in operation. This reminds me. Because the auxiliary boiler is being fired, you can see where the steam is coming out. It's releasing steam from the aux. boiler during a startup. And as I recall, we took this picture because the plant was not in operation.

Q. Okay. Now, another piece from your PowerPoint presentation of five weeks ago was called the Status of Commercial IGCC.

A. Yes.

Q. And you said that there's a new fleet taking advantage of 10-plus years of operation in the U.S. and Europe. When you were referring to fleet, were you talking about a new fleet of IGCC plants?

A. Yes, the ones that will be going into service in the 2012-2014 time frame.

Q. And then another part of the status of commercial IGCC was that there was a range of suppliers to choose from for a wide variety of coals and other feedstocks.

A. Yes, that's what that says.

Q. Is this a guarded reference to your chicken litter in the Netherlands and all those other exotic fuels? Is that what this means?

A. Oh, meaning all the lessons learned over the last 10 to 12 years at these four coal-based IGCC plants have given us the basis of design for this new fleet of 600-megawatt units, things that we hope will be able to prove higher availability, higher efficiency, things like that.

But their design points, we don't know whether or not they will actually work like that. You know, we design for these things. And the plan is that when these units go into service, after a couple of years, these enhancements and lessons learned will pay off, and we'll actually get -- hopefully, that IGCC will finally be as efficient as supercritical pulverized coal, might or might not have the same availability as supercritical pulverized coal.

But these are -- we've got -- at Wabash River, they advertise we have 1,600 lessons learned over the last 12 years, and we want to put those into our designs. And that's the kind of thing that I do when I design IGCC plants to try and make them better. That's my job.

Q. All right. Let's stay on that point. You said there's a range of suppliers to choose from, for a wide variety of coals and other feedstocks. Does that mean supplies -- a wide range of fuel supplies that can be used? Is that what you meant by that?

A. There are more -- it used to be that there was only one or two gasification technologies that would work on Powder River Basin coal or lignite, and now there are a few more technology suppliers that are available, like Mitsubishi Heavy Industries, possibly like the KBR technology that Orlando Utilities will be demonstrating at the Stanton B plant that Mr. Hicks talked about previously if that works on Powder River Basin coal. And again, they're going to be bringing in coal from Wyoming all the way to Orlando to test this technology. If it works, it will allow people out West one more option for being able to use Western coals. That would be a good thing. Having more competition would be good.

Q. Now, what did you say the letters EPC stand for?

A. Engineer, procure, construct. When you get a contract with an EPC supplier, as we do with ultra-supercritical pulverized coal units, a one-person point of contact that you go to, you contract with them, they do the engineering, they buy the stuff, they construct it, and they turn it over to you with guarantees. And I say that with ultra-supercritical pulverized coal units. Unfortunately, we have not yet been able to get that in the utility industry for IGCC.

Q. Well, then why did you write down as the third advantage in the commercial status of IGCC that EPC alliances can provide important guarantees?

A. Because that is a potential, what we're trying to get to in the IGCC industry. You see, when you buy an ultra-supercritical pulverized coal unit, the utility benefits from being able to get that contract so that things are date certain, performance, efficiency. We want to be able to get that. And if Florida Power & Light were to build an IGCC plant, they would want that same kind of guarantee.

But as we found out with Duke Indiana, when they filed with the Indiana Utility Regulatory Commission on April 2nd, they said for that project, EPC, a lump sum turn-key, meaning an EPC contract, is not a viable option for them, because it was going to be too costly, and they were unable to get those kind of guarantees. It is something that we are working for in the IGCC industry so that utilities can have something more certain, schedule, cost, performance.

Q. Okay. I'm actually giving you this piece of your PowerPoint presentation, page 46, from five weeks ago. And I would like that marked if I might. Would it be 181, Madam Chairman?

CHAIRMAN EDGAR: Yes, 181.

BY MR. GUEST:

Q. So I would refer you to the third dot -- is that what you call that thing?

A. Yes. It's my third point on that, which says, "EPC alliances can provide important guarantees." And we sure hope they will be able to do that.

Q. Well, but you didn't say might. You didn't say, you know, maybe can, may be possible in the future. You said alliances can provide important guarantees.

A. Well, to me, when I said can, meaning the potential to do. And it is their intent to do so, but none of them to date have done that. In fact, specifically, on the Duke Indiana case, they were not able to get an EPC guarantee from the GE-Bechtel alliance.

Q. So what you wrote in your PowerPoint was that they can provide important guarantees, but what you actually meant was that it might be possible at some time in the future to get those potentially, but maybe not?

A. Well, we certainly would like them to do that, but so far they have not done that. We will find out a little bit later this year when AEP goes a little further and when the Mesaba project goes further if they will be able to get these important guarantees from their EPC supplier. Without that, there's a lot of technical and economic risk for the utility.

Q. So now, we have -- you talked about there not being any technology for IGCC with carbon capture.

A. That's correct.

Q. And I'm turning to page 48 of your PowerPoint, and I see that you've listed three IGCC projects with carbon capture.

A. Those are three proposed IGCC plants that will not be in service until probably 2012 to 2013 that have said they intend to find a way to incorporate CO_2 capture into their projects. They have not yet found a way to do that, the technology to do so, or the use of the CO_2. I have worked on two of those three projects and am very familiar with them.

Q. So I take it they're using the Selexol approach to carbon capture?

A. They have done so little engineering that they're not even to the point that they have or have not selected the Selexol process, which can be -- if beefed up, can capture some of the CO_2, but they have not made that statement or choice yet.

Q. And then I'm turning to page 52 of your

PowerPoint from five weeks ago --

CHAIRMAN EDGAR: Mr. Guest, let me interrupt. I apologize. I misspoke. I mislabeled the document, so before I forget to do that, which does mean we're going to take a break in a few minutes, because when I start mislabeling, that means we need a pause. So to correct my misstatement, the photo is Exhibit 179, and the slide, Status of Commercial IGCC, page 48, will be Number 180. And I apologize for the interruption.

MR. GUEST: Thank you.

(Exhibit 180 marked for identification.)

BY MR. GUEST:

Q. Okay. You had a slide about IGCC availability improvements.

MR. ANDERSON: Chairman Edgar, there are a lot of questions on this presentation. Has counsel given the witness a copy of this presentation to follow along?

MR. GUEST: If you would like to, I would be happy to.

MR. ANDERSON: Just a courtesy, I think that might be useful.

MR. GUEST: Sure. I assumed that he knew it pretty well.

THE WITNESS: Yes, I do.

MR. GUEST: Since he said he gave it all the time.

CHAIRMAN EDGAR: Numerous times I think I heard.

THE WITNESS: Yes.

CHAIRMAN EDGAR: Let's do that. And again, I need to stretch and clear my head, so let's take about 15 minutes, and in the course of that. Thank you.

(Short recess.)

CHAIRMAN EDGAR: Okay. We will go back on the record.

MR. GUEST: I'm sorry.

CHAIRMAN EDGAR: That's okay. Mr. Guest, you're up.

BY MR. GUEST:

Q. Hi. We're back. We've given you all the sheets, which I think you're extraordinary familiar with.

A. Yes. I guess that's not all of my presentation, but it's some of it.

Q. Yes. These are the ones that we're interested in.

A. Okay.

Q. So we're on page 52.

A. Mine ends at 48, but I probably know what's on page 52.

There we go.

Q. And this page is entitled "IGCC Availability Improvements."

A. Yes.

Q. Now, when you say availability, are you referring to the availability in the sense of the fraction of the time that the plant is online? Is that what you --

A. Yes. As you asked the same question to Mr. Hicks, my answer would be the same in percentage of the time. And this particularly is for the entire IGCC plant, when it's in IGCC mode, not when you're firing the backup fuel. That's availability of IGCC.

Q. Okay. I'm glad you raised that, because that's one thing I wanted to get explained. Now, am I right that at the TECO plant that when you say backup fuel, they've got a natural gas line that runs up to the turbine?

A. No, they don't.

Q. They don't? Are there ones that do have -- well, what is the backup fuel? Let's go straight to the issue.

A. Where?

Q. At any IGCC plant.

A. Well, there are four of them, so one of them uses fuel oil and three of them use natural gas.

Q. Okay. All right. Let's just use the natural gas one to make life simple.

A. Okay.

Q. Which one would you like to talk about?

A. I don't have a preference.

Q. Okay. Well, let's just use fuel oil because it's easier. So the concept is that -- the way the combined cycle part works is that you have a turbine, which is essentially like a jet engine on a DC-10; right?

A. Yes.

Q. Okay. And what you do is, you get the syngas that comes out of the gasification part of the plant. That goes in there and makes that turbine spin like crazy and gets some kinetic energy that you get to drive a generator.

A. Yes.

Q. And when the gasification system is down for maintenance or whatever reason, you can put some diesel into that thing and make your jet engine spin around the same way.

A. Yes, at Polk Power Station.

Q. Right. And so it costs more.

A. I'm sorry?

Q. Does it cost more to run the backup?

A. Oh, yes.

Q. It's like driving a peaking unit at a power plant.

A. Yes, and even worse if you're using natural gas, because we know what the price of natural gas is now. If you were to use that backup fuel, the cost of electricity when you go to backup fuel is -- you know, if your coal is $2 a million Btus and your gas is 8, you're increasing your cost of fuel by four times. And you may not even run the unit like that because of the cost of fuel. You're not going to dispatch a unit, go from base load at $2 a million Btus, if that happens to be the cost of your coal, to $8 a million Btus on gas.

Q. So you can really increase avail -- when you talk about availability, are you including or excluding the availability to backup using diesel or natural gas?

A. Exclude. That's called --

Q. Exclude?

A. Yes. IGCC availability is when it's in IGCC mode, not when you take the gasification plant down.

Q. Okay. Now that I understand that, this piece of your PowerPoint, page 52, is IGCC availability and improvements, and you have -- the first bullet is lessons learned from 10-plus years of experience.

A. Yes.

Q. And one is, you've got materials of construction.

A. Yes. We've learned a lot about materials of construction over the last 10 to 12 years, and we're putting those design changes into this new fleet that we talked about, and hopefully that will provide better service.

Q. Why do you call them a fleet if they sit still? I mean, is there some --

A. Well, it's like a fleet of ships, a fleet of trucks. Well, okay. Everything is moving.

Q. All those things move.

A. It's a fleet of power plant units. It's just an industry term.

Q. Okay.

A. But they do not move, and if they do, there's a big problem.

Q. All right. Just checking.

What have you learned. Can you give us one example of improved materials of construction?

A. Yes. In the black water system -- and I know this kind of sounds technical, but in the GE gasification system, when you use coal and you gasify it, there is naturally some chlorine in the coal, particularly if the coal is from Illinois. The chlorine in the coal during the gasification process turns to chlorides, calcium chloride, ammonium chloride. It gets into the water. And chlorides past a certain concentration become corrosive, as when you have sea water and metals on a house that sits on the shore, all of a sudden you see corrosion. Chlorides do that.

So what we have learned is that the -- particularly at Polk Power Station, and at Wabash River -- they don't have a black water system, but in that same kind of a system, the materials of construction needed higher quality, different alloys to be more corrosion-resistant. And those are the kind of things that we've learned. In this kind of system, carbon steel is going to corrode. Don't use that. Use something better, more expensive.

Q. And another illustration might be that at the turn where the -- well, I'm not going to use another illustration because this is so technical.

A. There's just many things we've learned on materials of construction that will provide for and should provide for better and higher availability in the future. Those are the things that are going into this new number of --

Q. Okay. And then another item is spare equipment.

A. Yes.

Q. Can you give us a couple of -- one or two illustrations of spare equipment?

A. Just certain pumps that we found where one was not good enough, sometimes we'll put in two pumps on critical system where we found that that will increase the availability. One of the possible changes is in the main slurry pump. They're about a million dollars, so it's not something you say, "Well, let's go out and spend another million dollars for this new pump." But if it increases the availability of the unit to a point where it's cost-effective, those are the things that you do.

Q. And then another item is gasifier refractory?

A. Yes.

Q. What's that, and what's the improvement here?

A. As an example, the GE Energy, or what used to be the Texaco, the gasifier is metal, and it's lined with a refractory brick, several feet of it, and it protects the metal from high temperature. And the slag that is produced during the gasification, because it's operating at 2,500, 2,600 degrees, you have molten slag in there, and it is erosive and corrosive. So you protect the gasifier metal by having this high chromium refractory. It's an insulation material.

And what we found is that there were improvements made -- we found that in gasifier operation, since we didn't have a lot of gasifier operation history to go with, the first set of refractory at Polk Power Station eroded and corroded much faster than designed.

So we went back to the manufacturers, and we went back to Eastman Chemical that uses another Texaco/GE gasifier and worked with them and found -- and the manufacturers and said, "Is there something better," because when you change this out, you're down for 30 days and it costs you several million dollars. It's not something you want to mess up.

But on startup, because we had -- as you can see in the availability chart that you pointed out, on the first couple of years at Polk Power Station, there was very low availability, and that's because the unit was started up, shut down, started up, shut down. And refractory brick tends to crack, erode, corrode. And as I recall, it was a three-year liner refractory that lasted a year. So after the first year, we had to spend a lot of money and time down, and it affected the availability and the cost of the unit. We've learned a lot more on that now and have better refractory materials, as an example.

Q. And then burner design.

A. Yes. Even though it's not combustion in a gasifier, it's kind of --

Q. Yes, that's my question.

A. We call it a burner. It's really a process injector, and that's where the coal slurry and the oxygen goes into the gasifier, in a GE gasifier, and that's the materials that get gasified. And it used to be that they would only last about 30 days from erosion and corrosion. And we learned by making our own changes and talking with the GE and Texaco people and other gasifiers that we found improvements, and now Polk power station is able to go 90 to 120 days without taking out that process injector. When you take it down, you're bringing the gasification portion of the plant down, so that has a negative impact on availability.

So these are the things that we've learned. We're doing better, and all these things are being put into the new designs. And that's why I said in my opening summary that we expect all these things that we've learned to enhance the availability of IGCC in the future, but we won't know for another six years if all these things work.

Q. Okay. So let's turn to Exhibit 179, which is the picture of the Mulberry plant.

A. Yes, got it.

Q. The gasifier is that great big fat tower that looks like the top of a square 6-volt battery on the top sort of in the center right?

A. It is the structural steel structure at about the one o'clock position. It's a little over -- you know, over 200 feet tall.

Q. Okay. Now, you say the next generation -- you jumped ahead of me because you've got that in your hand there. The next generation should achieve 85 percent availability, 85 percent plus, over 85 percent. That's what you've got shown here?

A. Yes.

Q. And it looks to me like you've given reasons why, your three reasons why. Is that what I see there?

A. Yes.

Q. And so one is having a spare gasifier train.

A. Yes.

Q. Now, let me ask you a hypothetical question here. Let's just say that you wanted to get to 2,000, or 1,800 megawatts, and the way you decided to do it was with six 300-megawatt units sitting side by side, sort of the same way you have six locomotives pulling a giant long train. Is that the context where you would have a spare gasifier, so you would sort of have a seventh so if any one of them went down, you could, you know, use the spare? Is that the concept?

A. Not really, no, because actually, IGCC does not come in 300-megawatt chunks. It's not commercially available in that size.

Q. What sizes -- what's the big size that it's available in?

A. Well, right now, all that has been demonstrated is 250. What's being designed right now are 600-megawatt IGCC, so we're really only about a third of what the two units at Glades would do.

Q. Okay. So if you had three of those -- is this the first concept of the spare gasifier? Would that be the idea, that if you had three units to get you to 1,800, that you would add a fourth in as a spare? Is that the concept?

A. You might add a fourth, you might add a fifth. You have to do what's called reliability, availability, maintainability, or RAM analysis to find out will it get you to that point.

Q. But you think that a spare gasifier might get you to 90 percent?

A. It's like the "can" and "potential." The "may" is "might."

Q. Well, this one is definitely may.

A. Yes, this one says may, and it may, but we won't know for about another six years. And of all the IGCC plants being planned right now, only one, the Mesaba plant, plans to include a spare gasifier train. And in their calculations, they expect that it could reach 90 percent availability, and they're paying a lot of money -- it's about another $100 million to get that expectation of 90 percent. They will find out when they start up in 2011, 2012.

Q. That's about half the cost of the transmission lines here?

A. I don't know that.

Q. Okay. Backup fuel. Did we talk about this already, diesel?

A. We talked, you know, diesel, natural gas.

Q. Right. And that would be on top of the 85 or 90 percent; right?

A. It's possible that it could get you -- it could help you get there. We don't know yet, because none of these units are in service.

Q. You can't actually do that at a pulverized coal plant, can you? You can't --

A. Oh, yes. In fact --

Q. Well, how do you do it?

A. When you start up a pulverized coal plant, you're starting up on No. 2 fuel oil with the igniters, and you raise your steam pressure, and you can actually make enough steam where you can drive the steam turbine, get to a low load if need be, and then -- before you fire the coal to start up. So it is possible to do that.

Q. But when a PC plant goes down, you can't run it on diesel, can you?

A. Well, what do you mean by goes down?

Q. Well, stops working because you've got to work on it or something is broken.

A. Okay. And the same thing could happen to the combined cycle plant.

Q. Okay. But I think the concept that I'm bringing is, you keep talking about the gasifier as being a problem. Everything you've talked about has been gasifier issues; right?

A. I've answered your questions about the gasifier. If you want to talk about the reliability problems with the combined cycle plant, we can do that.

Q. Okay. Well, we can get to that. I would like to hear what you have to say, but let's finish this one. I think you finished your answer by saying the options have to be balanced against the cost of capital and fuel.

A. Yes.

Q. So I think what you're telling us here is that you've got a capital cost that you've got to put in, and then you've got a fuel cost that you balance for the backup, that is, you might -- you know, gas is really expensive, and you might not want to do it at all.

A. That's correct.

Q. Is that the idea? Is that what you meant?

A. Right. And that's what Mesaba did in the design of their plant for Minnesota. They decided instead of using more backup fuel, they put in the extra $100 million or so for the additional gasifier train to try and get a higher availability. It's the economic analysis that they did in their transmission system in Minnesota, and for them, that's the decision they made.

Q. Now, Florida Power has mostly natural gas plants, natural gas -- I mean Florida Power & Light has mostly natural gas generating plants?

A. I think that's correct. I haven't looked at their total mix.

Q. And how do those compare mechanically to the way the combined cycle part of an IGCC plant works?

A. Well, if we take a general natural gas-fired combined cycle plant and -- I hate to say general IGCC, because we only have four we can look at. The combustion turbine pieces are very different, because syngas from a gasifier is a mixture of carbon monoxide and hydrogen. That's what you turn the coal and water into in a gasifier.

In a gas-fired combined cycle plant like Florida Power & Light has, it burns natural gas, which is methane. Methane is a completely different compound from carbon monoxide and hydrogen that's in syngas, and those are very different from fuel oil.

So in the design of the combustion turbine part of the power block, the combustion nozzles or cans, kind of like the cylinders of a car engine, have to be designed for the fuel that you're burning. It's like that jet engine that's burning jet A fuel is burning something very different, and it's not natural gas. You know, airplanes -- that DC-10 does not run off a natural gas line, so its engine is a very different design and the combustors are a very different design. That's the basic difference.

Q. So the big picture, would it be a fair characterization to say it's like trying to run a jet engine on gasoline instead of on jet A? Is that the concept?

A. The design, yes, very different design.

Q. Okay. All right. Let's turn to a couple more things, unless you have something to add. Did you want to get into -- I think you wanted to talk a little about the turbine and heat recovery end of this thing about the gasifier. Did you want to say something about that?

A. No. I kind of feel like I'm giving my presentation.

Q. Okay. Well, let me move on to another presentation of a little more than a year ago.

MR. ANDERSON: Chairman Edgar, at the outset of this one, could the witness be given a copy of the document he's going to ask about?

MR. GUEST: Yes. There's only two images from this one. Well, maybe three. And tell me if you recognize these, if you would. Do you want me to distribute them all to see whether he remembers these things?

CHAIRMAN EDGAR: If you've got copies, we'll all take them.

MR. GUEST: We ought to give them out too, so that's what we're going to do.

THE WITNESS: Yes, I do remember this presentation in Houston with the Gulf Coast Power Association.

BY MR. GUEST:

Q. All right. While we're waiting for these to get dished out, let me ask you a quick question. There were problems with GE turbines, the GE jet engines? Are you familiar with those?

A. GE jet -- I don't really work with GE jet engines.

Q. Well, I mean with the turbines used in IGCC units.

A. There have been problems with many GE combustion turbines.

Q. And they were the 7F model?

A. Yes, 7F basis, or some of them, the newer ones are 7FA, and now they're making 7FBs, which are larger.

Q. And what was happening is, they were cracking the front disk in the turbine?

A. That was one of the problems that the GE combustion turbines had.

Q. And it also had a problem with a vane in the compressor?

A. As I recall, yes. There have been different problems that have occurred at Wabash River and Polk.

Q. Right. Those problems have since been fixed?

A. Yes.

Q. And those are good illustrations of what you were explaining to us, I think, are they not, of how you end up bringing this technology into full working order, that you find things that go wrong and you fix them along the way?

A. Yes. Sometimes the manufacturers find them, and sometimes you find them for the manufacturers.

MR. GUEST: All right. I think these have been handed out. Do I have one? I hope there's one left for me. I guess we would like to -- can we mark these together as --

CHAIRMAN EDGAR: We can mark them together.

MR. GUEST: 181.

CHAIRMAN EDGAR: 181, yes.

MR. GUEST: Consisting of three pages. And let's just call it -- well, what would you like to call it, Madam Chairman, because I never get it right.

MR. ANDERSON: A day, maybe?

CHAIRMAN EDGAR: Tempting, tempting. We will call it three pages of environmental permitting for IGCC power plants slides.

(Exhibit 181 marked for identification.)

BY MR. GUEST:

Q. All right. So the first page was what it was?

A. Yes.

Q. And now we're on another page which doesn't have a number on it, and it's called "Comparison of

Solid Wastes, IGCC Versus PC." PC means pulverized coal?

A. Yes, it does.

Q. And so we've got three columns. Let's just go through the three quickly. Solid wastes, IGCC you say has small volumes of sulfur and slag.

A. It can, yes, in this example.

Q. And then pulverized coal has large volumes -- what does FGD stand for?

A. FGD is flue gas desulfurization. That's the system on the back end commonly known as an SO_2 scrubber to remove the SO_2 from the flue gas.

Q. What are the by-products?

A. Different systems have different by-products. And what FGPP is planning to use is a system, an FGD system that would produce a commercial grade by-product gypsum that could be used in making wallboard and cement, or even used as an agricultural additive like Tampa Electric's FGD system does.

Q. Okay. And then the next the column is market use, and under IGCC you say, "Excellent markets for sulfur and slag." I think you've already talked about slag; right?

A. Yes. And I think we talked about sulfur.

Q. Yes, you talked about sulfur too, and TECO in

Mulberry is using some of it for the phosphate fertilizer.

A. They make sulfuric acid, not sulfur.

Q. And some of it is used -- well, you've already told us, so we don't need to go over it gain.

Now, I see that under pulverized coal, you say, "Markets may or may not exist."

A. That's correct.

Q. Okay. And then under land requirements, you only have temporary storage for IGCC, and pulverized coal, you need hundreds of acres.

A. It's possible. If you can't market it, you have to do something with it. As Mr. Hicks talked about a little while ago, you would have to put in the double lined storage area.

Q. Now, let's do the last page I've got for you.

A. Okay.

Q. Impacts of CO_2 capture.

A. Yes.

Q. That's carbon dioxide capture.

A. Yes.

Q. And we've got two columns, IGCC plant versus pulverized coal plant.

A. Yes.

Q. And the capture percentage is about the same.

That's the first row.

A. Yes.

Q. Unit output derating, what does that mean?

A. That means the -- let's say you have a 500-megawatt unit, which is what they did here, and I can discuss that a little further. How many of those megawatts the unit is derated from that number when you add the CO_2 capture system in.

Q. So that means how much juice it takes to run the capture process?

A. In this example, that's correct.

Q. And what is the 29, do you think? What does the 29 refer to?

A. That is 29 percent --

Q. Percent. I see.

A. Yes.

Q. I see. Whereas an IGCC plant has less than half that?

A. In this example.

Q. Okay. And heat rate increase, what's that?

A. The heat rate is Btus per kilowatt-hour. A higher number is worse. It's the reciprocal of efficiency. So if a heat rate goes up, that means the unit is less efficient.

Q. Okay. And so in your presentation, you counted the IGCC plant as two and a half times more efficient? Did I get that right?

A. The change in heat rate.

Q. Okay. So it's 40 percent more -- can you frame it for me?

A. Well, if you had a heat rate to start with of 10,000 Btus per pound and it increased 40 percent, it would now be 14,000 Btus per kilowatt-hour, the heat rate.

Q. I got it. So it really makes a big difference with a PC plant as compared to an IGCC plant?

A. In this example that Dr. Sikander Khan showed.

Q. And then a capital cost increase of 47 percent versus 73 percent for a PC plant.

A. Yes.

Q. And then -- what does COE stand for?

A. Cost of electricity. That's the bottom line of what it costs for the electricity production from both the IGCC plant and the pulverized coal plant in this EPA example.

Q. Okay. So that's 38 percent increase versus 66.

A. Yes.

Q. And that's not quite twice.

A. Yes. But I think it's interesting to note on this that when Dr. Khan, who I've spoken with many time, prepared this information, it was done by a consulting firm that had no experience in the design, operation, or construction of either IGCC or PC plants, and they did it based on a 500-megawatt plant. A 500-megawatt is not a commercial size for IGCC. The proper size should have been 600. And I sat down and discussed this with Dr. Khan, and he realized that there would be a problem with this information when it became public because it was not on a correct basis.

Since then, the EPA, Environmental Protection Agency, has put together an Advanced Clean Coal Technology Work Group. They have asked me to be on that work group along with some -- there are about 30 of us from industry, from Sierra Club, from NRDC, from Green Peace, from boiler and IGCC manufacturers, and they have asked us -- one of the things to do is to update this report, because EPA has found that nobody is using these numbers because they were not done on a credible basis. And this information was taken from Dr. Khan about a month after EPA released its report. Some of the same numbers are in this environmental footprints report, and EPA has determined that it is outdated and inaccurate and needs to be completely revised. And I will be working with EPA over the next few months to put in some of the newer numbers that we were talking about earlier this morning.

Q. So you're saying that this is outdated, but it hasn't been updated? Is that the short story?

A. That's correct. Nobody really uses these numbers anymore because there is a realization in the EPA and in the industry that these numbers are no good anymore.

MR. GUEST: Okay. No further questions. Thank you.

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

MR. KRASOWSKI: Yes, ma'am, I have a few.

CHAIRMAN EDGAR: Okay.

CROSS-EXAMINATION

BY MR. KRASOWSKI:

Q. Hi, Mr. Jenkins.

A. Hi, Mr. Krasowski.

Q. You worked on the TECO Tampa plant, right?

A. Yes, I did. I was deputy project manager.

Q. And that's the plant that was identified earlier as costing twice the amount that was originally projected, 303 million, and ultimately it cost 606 million; is that correct?

A. It's actually 609 million, but it's close enough.

Q. What happened there?

A. Well, as Mr. Hicks was talking about, on other IGCC plants that we were looking at, at this new fleet, before you do all of your preliminary engineering, you do a cost estimate. And since we had no large scale IGCC plants to use as a go-by, we did what we knew how to do, and we worked with the DOE and Texaco at the time. We did a preliminary estimate. We filed that with DOE. And when it came time to do all the detailed engineering -- and when you do detailed engineering, you refine that cost estimate. And we found when things got real, so to speak, that the cost was considerably more than we first thought.

And then that $609 million number also includes some additions after the unit went into service in 1996, and DOE partially co-funded some of those cost overruns. You can see that in the Polk Power Station final report that is publicly available from DOE.

Q. How did the cost of operations estimates work out ultimately?

A. As I noted, some of the availability in the up-front years was poorer than designed for. The operating and maintenance costs were higher. Things like replacing that refractory when it was supposed to last three years and lasted one, putting in new corrosion-resistant or better corrosion-resistant piping in the black water system, changes in the brine concentration, the fixes on the combustion turbine that had -- you know, some were warranty and some were not. So overall, the operating and maintenance costs were higher than we had planned. It's a chemical plant tied to a power plant. It's not an easy thing to run, although they do a fine job at Polk Power Station.

Q. And that was a 250-megawatt facility?

A. Yes, 250 net.

Q. Okay. I don't know if it was you, but a while back I saw a presentation. Somebody that had worked there or was working there had spoken about that facility, and they mentioned something about the reliability where this IGCC component operated like 35 or 37 percent of the time, and they did have to go to backup pretty -- you know, if only 30 percent of the time this was working. And I guess they mentioned -- I believe they mentioned using gas. Is that your understanding? How much -- how reliable was that facility?

A. The backup fuel at Polk Power Station is fuel oil, and the reason we did that is because there was no natural gas line at Polk Power Station. Now there is, and there are several gas-fired simple cycle combustion turbines there, peakers. I believe in the exhibit that Mr. Guest passed out was one of my slides that shows the availability of all of the IGCC plants in the world, all four of the coal-based ones, and it shows what the actual numbers for Polk Power Station were in the early years, and we had very low availability, 30s. I think it took three years to get to 60 percent. And there were times when we did use fuel oil as a backup fuel to keep the combustion turbine online and generating power, particularly in the summer months when you could dispatch that higher priced power.

Q. Okay. On the solid waste category, is that municipal solid waste, or are you talking about a specific -- like tires or wood waste, a dedicated stream of a specific material, or are you talking about general garbage?

A. This is a solid by-product coming out of the gasification system in contrast to what's going in, the slag, the ammonium chloride brine. Those would be considered solid by-products.

Q. Okay. I'm sorry. So it's not the use of solid waste materials to generate syngas?

A. Correct.

Q. Okay. Does this gasification process -- I don't know if you're familiar with this, but a few years back, there were proposals floating around to process solid waste through a syngas, a gasification type of operation, and they had their main base in Wollongong, Australia, was one, Brightstar?

A. Yes.

Q. You know --

A. I'm very familiar with the Brightstar technology.

Q. Is this -- excuse me. Is it the same type of operation? Would you use the same gasifier designed for waste, the one, you know, the one you're designing for a certain type of coal. Is this the same machine?

A. It is a very, very different machine. Designing to handle municipal solid waste, which has a lot of moisture, a lot of metals, a lot of glass, and has very low heating value, the gasifiers for municipal solid waste are a completely different universe than the type of gasification equipment that is used for coal and/or petcoke. We have GE, CococoPhillips, and Shell as the big three, we call them in the IGCC industry. None of those companies are involved in municipal solid waste gasification. And then we have companies like Brightstar, who unfortunately are no longer in business, but other --

Q. It all depends on how you look at it, fortunately, unfortunately.

A. Okay. Yes, but they are no longer in business.

Q. No longer in business.

A. The Wollongong, Australia, plant was an economic failure for them, not a technical one. But you have a completely different universe of companies that are involved in municipal solid waste gasification than are in coal. Those are much smaller, 10 to 20 megawatts, where here we're talking 600. But then again, that's only a piece -- that's only a fraction of what we do with ultra-supercritical pulverized coal, where we're talking about 1,800 megawatts, very -- municipal solid waste gasification, 20; 1,800 megawatts with supercritical coal.

Q. The Wollongong facility never worked for more than eight days in a row. It was a technical failure as well as an economic, the technical inability. But that's off the track. Excuse me. I'm sorry.

To get back on track, as was mentioned earlier, if you have these 250-megawatt units, why not put eight of them side by side and then have two in reserve, and then you could design and dedicate two of them to coal, one to gas, one to tires, you know, one to biofuel. If you could design, and then you have the cross -- as they say in the space industry -- what is that, you know, where you back up, you have multiple backups? But that would be very expensive, I suppose.

A. Yes, it would.

Q. Okay. So forget that.

A. Spare gasifiers, as I noted, are about $100 million, a gasifier train. That's a lot of money.

Q. And beyond that, the ratepayer would be floating this if some people get their way. It's not a very attractive idea to me.

A. Yes. Well, you either pay for the spare gasifier train or you pay for a lot of natural gas and the gas transmission line to bring it in. And every time you fire backup natural gas in your non-working IGCC plant, somebody has got to pay for that high cost power.

Q. You know, earlier you said -- and this is not a trick question, but earlier you said that the technology is evolving at an amazing rate. I think you were referring to the capture and sequestration elements, those separate elements or together. And I understand you're not speaking as an expert in efficiency or conservation or environmental; right? But from your position here, what would be wrong, if it's possible -- well, what would be wrong, if it's possible, with delaying building either one of these technologies for two and a half, three years, until we can take advantage of what's going to happen in the next year or two? Are we in that much of a hurry with this to --

A. Well, on the technical side, obviously, we don't know, as I said, that all of these changes are going to be proven from six years from now, not two or three, but six years from now. I don't think you can plan to wait on what might come.

The other issue on the whole issue of when the capacity is needed, that's for someone at Florida Power & Light to talk about. I mean, that's not my area of expertise, in the generation planning and meeting capacity additions.

Q. So in your view, it's kind of six years out before we get a solid answer on the IGCC option?

A. Yes. And my job, it says gasification services in my title. I want these IGCC plants to work and work reliably and have high efficiency, or else I'll have to find something else to do. But my expectation is, all these things that we're learning we're going to put in these designs, but it will be six years before we know whether they'll really work or not. You know, I'm waiting, and I'm optimistic.

MR. KRASOWSKI: Well, thank you very much, Mr. Jenkins.

THE WITNESS: Thank you.

CHAIRMAN EDGAR: Are there questions from staff?

MS. FLEMING: No questions.

CHAIRMAN EDGAR: Commissioners? No questions.

Mr. Anderson. No? Okay. Let's do the exhibits.

MS. BRUBAKER: I believe there are no direct exhibits for Mr. Jenkins, and so that leaves us with Exhibits 179 through 181 proffered by Sierra.

CHAIRMAN EDGAR: Thank you. Mr. Anderson, any objection?

MR. ANDERSON: No objection.

CHAIRMAN EDGAR: No objections? Okay. Then seeing no objections, we will enter 179, 180, and 181, into the record. Thank you.

(Exhibits 179, 180, and 181 admitted into the record.)

MR. ANDERSON: Chairman Edgar, just as a procedural matter, we have a number of witnesses available. If people have comparatively little for Mr. Yeager, if it would work for people, we would like to take him next.

CHAIRMAN EDGAR: Mr. Beck, Mr. Guest, Mr. Krasowski, are you amenable to taking Mr. Yeager out of order to be the next witness?

MR. GUEST: Of course, we're amenable to whatever people want to do. I just had one of my witnesses ask me if we don't make it tomorrow, do you think we'll spill over to Friday or spill over to another day?

CHAIRMAN EDGAR: We will not spill over to Friday, because there are conflicts on Friday. However, we do have some time available Monday, which is the 30th.

MR. GUEST: Monday the 30th. Okay. That bears on what we do, so may I confer?

CHAIRMAN EDGAR: Of course.

(Off the record briefly.)

MR. GUEST: I think if you give us two minutes, we might be able to speed things up.

CHAIRMAN EDGAR: Oh, okay. We will take two minutes.

(Short recess.)

CHAIRMAN EDGAR: Yes, sir?

MR. GUEST: We have elected to stipulate the witness's testimony.

CHAIRMAN EDGAR: Okay. Mr. Guest, are you referring to Mr. Yeager?

MR. GUEST: Yes.

CHAIRMAN EDGAR: Mr. Krasowski, Mr. Beck. Mr. Beck concurs, and Mr. Krasowski.

Staff, I think I asked you that earlier, but remind me. No questions. Okay.

Commissioners, you're okay with that.

Okay. Then I think that -- I'm sorry. I didn't even ask you, did I? I apologize. Mr. Anderson.

MR. ANDERSON: That's delightful. I just wanted to make sure we offer his exhibits into the record as well.

CHAIRMAN EDGAR: Okay. Well, then in the interest of me not forgetting something else, let's go ahead and enter Mr. Yeager's prefiled rebuttal and direct, direct and rebuttal testimony into the record. And I need to find the numbers of the exhibits. Thank you. Exhibits 61 and 62 will be entered into the record as well. Ms. Brubaker, does that take care of that?

MS. BRUBAKER: I believe it does.

(Exhibits 61 and 62 marked for identification and admitted into the record.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF WILLIAM L. YEAGER

DOCKET NO. 07_____-EI

JANUARY 29, 2007

Q. Please state your name and business address.

A. My name is William L. Yeager. My business address is Florida Power & Light Company, Engineering and Construction Division, 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. I am employed by Florida Power & Light Company (FPL) as Vice President of Engineering and Construction.

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

A. I am responsible for engineering and construction of all generation projects for the Company, as well as all procurement and start-up activities. This includes the proposed FPL Glades Power Park (FGPP) Units 1 and 2.

Q. Please describe your educational background and business experience?

A. I received a Bachelor of Mechanical Engineering degree from the Georgia Institute of Technology in 1982. I received an MBA from the University of South Florida in 2003. I am a registered professional Engineer in the State of Florida and a member of the American Society of Mechanical Engineers.

My entire 24 years of work experience has involved the design, engineering and construction of electrical power plants, in which I have held numerous positions with increasing responsibilities. My career began as a mechanical engineer with FPL in 1982. In 1987, I was lead engineer for the preliminary engineering phase of Lauderdale 4 and 5, two 400 MW combined cycle repowered units that came on line in 1992.

From 1988 to 1991, I was the Project Engineering Manager for FPL's Martin Coal Gasification Combined Cycle Project. This project consisted of the permitting of the Martin Combined Cycle Units 3 and 4, two 400 MW natural gas fired combined cycle plants; Martin Coal Gasification Combined Cycle Units 5 and 6, two 400 MW integrated gasification combined cycle plants, and the retrofit capability for converting Units 3 and 4 to coal gasification. This project is noteworthy in that it represented one of the first detailed reviews for the use of constructing a large scale 400 MW integrated combined cycle plant using coal as a feedstock in the United States. Due to poor economics (e.g., high O&M and poor reliability) and concerns with scale-up of the technology, FPL only constructed the natural gas fired Martin Combined Cycle Units 3 and 4 portion of the project.

Following the completion of Martin 3 and 4 in 1991, I held various management positions at the FPL Martin Plant site. In 1995, I became Operations Manager for FPL Energy's predecessor, ESI Energy, Inc., an unregulated affiliate of FPL. This included operations responsibilities for fossil fueled power plants which included natural gas, oil and coal, and renewable energy power plants which included wind, solar and wood by-products.

From 1997 to 1999, I was a General Manager within the Power Generation Division for FPL responsible for providing engineering for combustion turbines and balance of plant components. In this role I had responsibilities for fossil fueled power plants which included natural gas, oil and FPL's coal plants St. Johns River Power Park Units 1 and 2, which FPL has a 20% ownership and Scherer Unit 4, in which FPL has a 76% ownership.

From 1999 through 2001, I was Plant General Manager of FPL's Manatee Plant.

From 2001 to 2005, I was the Director of Engineering in the Engineering and Construction Division with overall responsibility for the engineering of all FPL power plant projects.

In my current position as Vice President of Engineering and Construction I am responsible for the engineering, construction and start-up of all power plant projects for FPL. This position includes an overall responsibility for reviewing, monitoring and performing any technical evaluations on all generation technology options for FPL. This includes providing technology assessments, which would include the estimation of construction costs, operating costs, and performance projections such as heat rate, output, availability and reliability, requiring an understanding of the most current technology advancements. For a solid fuel power plant, such technological options include sub-critical pulverized coal (SPC), supercritical pulverized coal (SCPC), ultra-supercritical pulverized coal (USCPC or advanced technology coal), circulating fluidized bed (CFB) and integrated gasification combined cycle (IGCC) plants.

Q. Are you sponsoring an exhibit in this case?

A. Yes. I am sponsoring an exhibit consisting of the following documents which are attached to my direct testimony:

Document No. WLY-1	FGPP Construction Cost Components
Document No. WLY-2	FGPP Indexing

Q. Are you sponsoring any part of the Need Study for this proceeding?

A. Yes. I co-sponsor Sections III.E, F, G and Section V.A.4.a.(i) of the Need Study. I also sponsor Appendix H of the Need Study.

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

A. I am testifying in support of FPL's Petition for Determination of Need. I describe some of the key considerations in determining the technology proposed to be used at FGPP and explain why USCPC is the best option among the solid-fuel technologies considered. I discuss FPL's expected in-service dates for FGPP 1 and 2, and describe areas of uncertainty associated with a project of this size and scale, particular as those uncertainties relate to the schedule. Finally, I explain the approach FPL has employed to produce reasonable estimates for the cost of FGPP 1 and 2.

I. TECHNOLOGY

Q. What advanced coal generating technologies were considered by FPL?

A. The technologies that were considered are: SPC, USCPC, CFB and IGCC. Cost and performance estimates were provided as part of the initial assessments performed in the fall of 2004 for FPL's Report on Clean Coal Generation, a report that was provided to the FPSC on March 10, 2005. Updated cost and performance estimates were also provided to FPL's Resource Planning in December of 2006.

Q. Please provide a brief overview of the technologies considered.

A. Most coal burning power plants use SPC boilers, which are the most predominant. SCPC plants have been in use since the initial introduction in the 1960s, while USCPC have been in use since the mid 1990s. The most advanced coal-fired pulverized coal plants, USCPC, have been in successful operation starting in 1994. There are currently 17 USCPC plants in operation with another 25 plants currently under construction, mostly in Europe and the Far East. The industry's technology choice is trending toward USCPC due to its inherent performance advantages over the older SPC technology.

The two commercially available technologies that use the fluidized bed boiler are the bubbling bed (BFB) or CFB. The CFB technology is the most prevalent of the fluidized bed technologies used today. The first utility-grade CFB unit was a 110 MW Department of Energy (DOE) Clean Coal Demonstration Project constructed in 1987. The largest CFB unit operating in the United States is the 300 MW Jacksonville Electric Authority (JEA) Northside plant. The technology is considered to be a viable technology in 300 MW sized boilers and typically is used in locations where fuels such as lignite or a coal waste product are readily available, which is not the case in South Florida.

FPL also considered IGCC. IGCC utilizes a gasification process which dates back to the 1800s. In fact, the first patent was granted to Lurgi GmbH in Germany in 1887. Though the gasification process itself is considered mature, it is the integration of the gasification process into a combined cycle power plant that is not currently viewed as viable for large scale reliable power generation applications. In connection with my responsibilities when I was the Engineering Project Manager of the Martin Coal Gasification Project between 1988 and 1991, FPL extensively evaluated the IGCC process and determined that the technology had not matured to a point where it would be competitive with other technologies. Issues at the time included higher construction and operating costs, lower availability due to reliability issues, and marginal performance characteristics, e.g., heat rates greater (meaning less efficient) than USCPC. FPL continues to reassess the technology each year as part of its generation technology planning. However, FPL's current evaluation of IGCC indicates that there have not been sufficient advancements in the technology: thus, FPL continues to conclude that IGCC is not the most cost effective solid fuel alternative currently available.

Q. Please comment on FPL's selection of the USCPC technology from your perspective as the Vice President responsible for reviewing, monitoring and performing any technical evaluations on all generation technology options for FPL.

A. The detailed reasons for the technology selection are discussed by other witnesses, including David Hicks, Steve Sim, and Steve Jenkins. From my perspective, USCPC is the right choice for FPL and its customers. The USCPC technology has a substantial track record of successful application in the industry. There are currently over 17 USCPC applications operating worldwide with 25 currently under construction. Also, in the case of the USCPC and SPC technologies, single units in the 1,000 MW range already are operating reliably; therefore, there are no scale-up risks associated with these technologies.

In contrast, there are only four applications operating worldwide for a coal-fired IGCC electric generating plant – a technology that has been available far longer than USCPC. Moreover, the four operating IGCC plants, which include two in the United States, are small scale (less than 300 MW) demonstration projects, built with substantial government funding, and have not met initial projections of cost, efficiency and reliability performance. Although there are plans to increase the technology's commercial size to 600 MW, to date no unit has been built at this scale. IGCC has substantial scale-up risk.

Simply stated, in contrast to USCPC, cost, schedule and performance risks associated with IGCC were determined to be unacceptable.

Q. **What other considerations or advantages relative to advanced technology coal influenced FPL's technology selection?**

A. As I discussed, the technology and construction risk also have an impact on the potential for schedule risk. It is FPL's desire to bring fuel diversity into our current mix of fuels used for our generation fleet in the 2013 and 2014 timeframe. The selection of USCPC provides us with the best plan in meeting this timeframe.

II. CONSTRUCTION

Q. **What is the expected construction schedule for FGPP Units 1 and 2?**

A. FPL will begin construction upon receipt of the necessary federal and state certifications and permits, currently estimated to occur as early as February 2008. The expected construction duration for FGPP as a whole is approximately 64 months, with Unit 1 taking approximately 52 months to complete and Unit 2 following approximately 12 months later. For reasons that I discuss more fully below, it has become increasingly clear that, due to market conditions relating to demand for power generation equipment and engineering, procurement and construction (EPC) services, as well as other uncertainties associated with the permitting and construction schedules, it is more likely that the in-service date of FGPP 1 will occur later in 2012 or early in 2013 instead of the previously projected in-service date of June 2012 and, likewise, that the in-service date of FGPP 2 will occur in later 2013 or early 2014, instead of June 2013. For purposes of the analysis, however, FPL is assuming in-service dates of June 1, 2013 for Unit 1 and June 1, 2014 for Unit 2.

Q. Please describe the factors that lead you to conclude that the prospects for meeting the summer of 2012 and 2013 in-service dates for FGPP 1 and 2 are less likely than previously thought?

A. This is a project of enormous scope and size, requiring many different approvals and permits, large pieces of equipment, separately ordered and manufactured with long delivery lead times, and a massive labor force of craftsmen and skilled labor. Thus, there are many aspects of FGPP that could negatively affect the ability to achieve the earlier in-service dates.

Obviously, a first, critical step in the development of FGPP is to obtain all of the regulatory approvals necessary to commence construction. At the state level, this includes the Land Use and Certification Orders from the Florida

Siting Board. Federal level approvals include the Prevention of Significant Deterioration (PSD) Air Construction permit, the Underground Injection Control (UIC) permit and the Army Corp of Engineers (ACOE) Dredge and Fill permit. These approvals are required not only for the power plant site, but also for the off-site transmission improvements, which include the Hendry sub-station described in Mr. Coto's testimony. There are numerous other permits and approvals that are required along the way.

Delays in the delivery of major equipment or difficulties in obtaining adequate labor for a project of this scope and scale could also negatively affect FGPP's originally planned in-service dates. For example, the current backlog in specialty fabrication facilities, which include large forgings for steam turbines, boilers and fuel handling equipment, are such that any shop delays resulting from labor issues, weather, or factory malfunctions could result in an extended delay in the delivery of the equipment. Obtaining adequate labor itself at the FGPP site will present a significant challenge for the project. The project is expected to employ, on average, 1,600 construction workers over the 64-month construction timeframe. Though the general region around the FGPP site has an estimated construction labor force of 65,000, there will be a significant portion of the labor force which will require specialized skills generally not found in the region. These skilled craftsmen, such as boilermakers, welders qualified in high alloy welding and supervision experienced in power plants, are expected to be in high demand given the number of projected coal generation projects being constructed in the United States. Current projections are that as many as 45 coal units will be under construction in the United States during the 2008 to 2013 timeframe.

Because of the significant uncertainties presented by these and similar factors on a project of such scale, and their potential impact on FGPP's construction schedule, it is simply not possible to project with sufficient confidence the original in-service dates for FGPP 1 and 2 of June 2012 and June 2013, respectively. For these reasons, we have based our project plan and the associated analyses on nominal in-service dates of June 1, 2013 and June 1, 2014, which I am confident can be met. However, as I previously indicated FPL intends to pursue a schedule that will bring FGPP on-line earlier.

Q. **What is FPL doing to mitigate these potential schedule uncertainties for FGPP Units 1 and 2?**

A. FPL has taken several steps to minimize and mitigate schedule uncertainties. Such actions taken have included:

- Submitted all permit applications necessary for the start of construction. This included the Site Certification Application, PSD Air Construction application, Underground Injection Control exploratory well application and the ACOE Dredge and Fill application.
- Initiated procurement of major equipment, which includes the boilers, steam turbines and the pollution control equipment.

- Secured EPC pricing for FGPP.

Q. What is the current status of the certifications and permits required to begin construction of FGPP Units 1 and 2?

A. FGPP's PSD Air Construction and the Underground Injection Control exploratory well applications were submitted on December 19, 2006. While the Site Certification and ACOE Dredge and Fill applications were submitted on December 22, 2006.

III. INSTALLED COST

Q. What does FPL estimate as the installed cost for FGPP?

A. The expected installed cost for FGPP is $3,456 million (2013 dollars) for Unit 1 and $2,244 million (2014 dollars) for Unit 2, for a total cost of $5,700 million. For Unit 1, this cost includes $2,396 million for the power plant, $125 million for land acquisition for the power plant, $73 million for land acquisition for the off-site transmission system, $201 million for the transmission interconnection and integration, and $661 million in allowance for funds used during construction (AFUDC) based on an in-service date of June 2013. For Unit 2, this cost includes $1,668 million for the power plant, $195 million for the transmission interconnection and integration, and $381 million in AFUDC based on an in-service date of June 2014. All land acquisition costs are included in the costs of Unit 1.

The power plant costs include site development, major equipment, EPC, start-up and project staffing. The site development costs include, but are not limited to: costs of engineering, designing, and permitting the power plant; costs associated with site and technology selection; initial site clearing, filling of the site up to finished grade, all roadways, stormwater facilities and the on-site rail loop. Major equipment costs would include boilers, steam turbine generators, and the pollution control equipment. EPC costs would include balance of plant equipment such as the stack, cooling towers, transformers, condensers, fuel and limestone unloader, reclaimer and crushers, and bulk materials such as concrete, steel, cable and labor. A majority of the power plant costs are based on firm proposals, based on which we are in advanced stages of negotiation. This includes the EPC, boilers, steam turbine and pollution control equipment costs.

The transmission interconnection and integration costs include all of the on-site switchyard and the off-site electrical improvements necessary to interconnect the FGPP power plants to the FPL transmission system. A more detailed discussion is included in Mr. Coto's testimony.

The power plant land cost is based on a negotiated land option agreement. Off-site land costs for the transmission upgrades are estimated and discussed in more detail in Mr. Coto's testimony.

The allowance for funds used during construction is based on projected cash flows for the project.

The components of the total plant cost are shown in Document No. WLY-1.

Q. Do you propose that the cost estimate upon which a determination of need would be based include certain indexed components?

A. Yes. A portion of the costs upon which the Commission would base its decision in granting a determination of need should be based on indices.

Q. What portion of the estimated capital costs of FGPP do you propose should be based on indices?

A. There are two components of the total estimated capital costs for the power plant that should be based on indices: escalation for labor costs in the EPC agreement and the escalation for high alloy steels and metal costs in the pollution control equipment (e.g., Fabric Filter, Wet Flue Gas Desulphurization and the Wet Electric Static Precipitator). The portion of the total estimated cost representing the projected escalation for labor costs, including AFUDC, in the EPC scope is nominally $594 million, or about 10% of the total capital cost of FGPP. The portion of the total cost estimate representing the alloy material component of the pollution control equipment is nominally $151 million, including AFUDC, or about 3% of the total capital cost of FGPP.

Q. Why should these two cost components be based on indices?

A. These two cost components are subject to significant market price risks that suppliers simply are not willing to assume. Essentially, these indices address market risks over which neither the supplier nor FPL will have control. Thus, in each case, it is necessary to apply indices for these particular cost components. For the EPC pricing, the labor component will be indexed to a rate derived from the United States Department of Labor Bureau of Labor Statistics County Employment and Wages Bulletin, which is outlined in Document No. WLY-2. For the pollution control equipment contracts, high alloy steels and metal costs will be indexed to published market indices for high alloy steels and metals used in producing the equipment.

Q. Why are suppliers unwilling to accept cost risks without imposing a significant contingency price premium?

A. Over the last two years the industry has experienced sharp increases in labor and material costs that have adversely impacted the suppliers and contractors. In general the costs of bulk material such as metals have also increased substantially. Changes in the backlog of shop orders have risen significantly as a result of the number of announced orders for coal projects in the United States and abroad. This competition for suppliers has placed a premium on the acquisition of major equipment for FGPP.

In some cases, like the pollution control equipment (e.g., Fabric Filter, Wet Flue Gas Desulphurization and Wet Electric Static Precipitator), the market is so saturated with buyers and orders that firm pricing is not even attainable. This market saturation is due not only to the current backlog of proposed new coal projects, but also to the numerous coal plant retrofit projects underway. Such retrofit projects are in response to new environmental compliance programs such as the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR) and Best Available Retrofit Technology (BART).

Q. Please explain how the proposed indexing mechanism for these power plant costs would work.

A. The current project cost for the power plant includes the projected escalations based on the current projections for the future value of each index. In the event that the actual value of the index is higher than projected, the contract cost would increase. Any increases in the contract cost due to such a higher than projected value for the index would result in an increase in the total project cost. FPL proposes that the total approved cost of the project approved by the Commission be based on the indexing mechanism presented in Document No. WLY-2 for the labor component in the EPC costs and a similar approach utilizing a yet to be determined material-based index for pollution control equipment.

Q. Please describe the potential cost impact of the indexed portion of costs on the total estimated installed cost of FGPP.

A. The total cost estimate includes assumptions regarding how the index will behave. Therefore, depending on the actual movement of the relative indices, the total project cost could be slightly higher or lower. For example, in the case of the EPC labor costs, if the actual labor escalation were double the 4% rate of growth reflected in the filed cost of FGPP over the entire construction period, the increase in labor costs would be $146 million. In the case of the high alloy steels and metal for the pollution control equipment, if the actual material escalation were double the 4% rate of growth reflected in the filed cost of FGPP over the entire construction period, the increase would be approximately $6 million.

Q. What has FPL done to ensure the reasonableness of the total estimated installed cost of FGPP?

A. FPL secured firm pricing for three major pieces of equipment and the EPC. Specifically, FPL sought and obtained competitive equipment pricing for the boiler, steam turbine and the pollution control equipment. The selection process included at least three bids for each of the major equipment procurements. For the boiler and steam turbine, the process resulted in firm pricing. For the pollution control equipment this resulted in pricing with the majority of the costs firm and the remaining portion subject to an adjustment based on a predetermined index, as I discussed earlier. The immense scope of this project, in the first instance, necessarily limits the number of potential EPC contractors. Thus, the EPC pricing was based on an initial inquiry to three major contractors with coal engineering, procurement, and 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. FPL promptly undertook to negotiate a market-competitive agreement for the EPC services. In negotiating a market-competitive agreement, FPL employed two fundamental approaches: first, the terms and conditions used were from the competitively-bid West County Energy Center EPC contract; second, the cost was benchmarked against a similar competitively-bid project. These costs included quantities for materials and equipment along with fees and labor man-hours adjusted for scope differences between the projects. Scope differences included the unit size and number of units (one versus two) along with site and region differences.

Q. **What is your conclusion regarding the reasonableness of the estimated costs of FGPP?**

A. For the reasons I have discussed above, the estimated costs for FGPP are reasonable.

Q. **What else has FPL done to satisfy itself that the estimated costs of FGPP are reasonable?**

A. In order to ensure the reasonableness of FGPP's estimated cost, FPL also hired the services of a consultant, Cummins & Barnard, who has performed an independent detailed review of the installed cost estimate for FGPP. In his testimony, Mr. William Damon of Cummins & Barnard discusses the scope and results of his review which concludes that the estimated installed cost for FGPP are reasonable and competitive.

Q. How have the expected costs of constructing generating units changed over the last two years?

A. The costs of constructing all types of electric generating units have increased substantially over the last two years and they are expected to continue to increase. These cost increases are similar to what was observed back in the early 2000 to 2005 timeframe when the demand for combined cycle plants increased significantly in the market place. These market conditions, characterized by intensive demand and comparatively limited supply is also occurring in the pulverized coal plants, with approximately 45 units projected to be coming into service in the 2008 to 2013 timeframe. As the demand increases for the supply of major equipment along with services, the market pricing changes in favor of the provider. Other cost stresses in the market include recent increases in bulk material costs for concrete, steel, and high alloy metals.

As these cost increases, both actual and expected, relate to the construction of a coal unit, I would note that in FPL's Report on Clean Coal Generation, provided to the FPSC on March 10, 2005, the total installed cost of FGPP (excluding transmission interconnection and integration) was estimated to be $3,200 million for 1,700 MW or $1,880/kw. In our most recent Ten Year Power Plant Site Plan 2006-2015 filing dated April 2006 the total installed cost of FGPP (excluding transmission interconnection and integration) was estimated to be $3,500 million for 1,700 MW or $2,050/kw. The current estimate, when adjusted to exclude the transmission interconnection and integration cost is $4,982 million for 1,960 MW or $2,542/kw. These increases in cost are attributable to the various changes in the market conditions that I have discussed and which are affecting the costs of all forms of generation.

Q. What are the bases for the cost estimates for the combined cycle units against which FGPP was compared?

A. The basis for the cost estimates for these combined cycle units are FPL's West County Energy Center contracted costs with adjustments for escalation, including adjustments for current labor and high alloy steels and metals markets, site differences, including site development, land, and transmission and integration.

The costs for a combined cycle plant also are increasing. Similar pricing adjustments were observed when FPL developed its cost for the West County Energy Center in 2005 when compared to the 2003 developed costs for the Turkey Point Unit 5 Project. However, the impact to the overall cost is not as dramatic. Mitigating factors include: (1) the percentage of construction labor to the total project cost is less for a combined cycle plant than a pulverized coal plant; (2) the pulverized coal plant involves a higher percentage of high alloy steels and metals; and (3) the number of planned combined cycle plants has significantly declined resulting in reductions in combustion turbine pricing.

Q. Please summarize your testimony.

A. USCPC technology is the most mature technology when compared to CFB and IGCC technologies. This technology provides FPL with the best opportunity to meet its generation needs by 2013 with a solid-fuel option. The FGPP installed-cost estimate upon which FPL's request for a determination of need is based is reasonable. We have secured firm pricing for a majority of the power plant costs, which would include the EPC, boiler, steam turbine and pollution control equipment, with a portion of those costs subject to market indices. FPL also has confirmed the reasonableness of the estimate through the independent detailed review of the installed cost estimate for FGPP by an outside engineering consultant who has concluded that the estimated cost of FGPP is reasonable.

Q. Does this conclude your direct testimony?

A. Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF WILLIAM L. YEAGER

DOCKET NO. 070098-EI

MARCH 30, 2007

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

A. My name is William L. Yeager. My business address is Florida Power & Light Company, Engineering and Construction Division, 700 Universe Boulevard, Juno Beach, Florida 33408.

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

A. Yes.

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

A. The purpose of my rebuttal testimony is to respond to the testimony of Mr. David A. Schlissel in which he asserts that FPL did not analyze the risk of increases in "the actual capital cost of completing FGPP and placing the generating units in commercial operation."

Q. **Do you agree with Mr. Schlissel's contention that FPL did not analyze the risk of increases in "the actual capital cost of completing FGPP and placing the generating units in commercial operation"?**

A. No. To the contrary, my direct testimony is quite clear that FPL not only recognized the risk of cost increases, but took significant steps to mitigate those risks. For example, as I testified in my direct testimony (Page 17, Line

10), "FPL secured firm pricing for three major pieces of equipment and the EPC." By doing this, FPL has significantly reduced the risk of the types of cost increases being experienced by similar projects throughout the country.

Q. **Does Mr. Schlissel's testimony address the impact that securing firm pricing for three major pieces of equipment and the EPC has on cost certainty?**

A. No, Mr. Schlissel misunderstood my testimony. Mr. Schlissel cites one sentence from my testimony (page 17, lines 17-23) in his attempt to demonstrate that, because the projected costs of building new coal plants have increased dramatically over the past few years, the risks of increasing capital costs had not been addressed. The partial quote relied upon by Mr. Schlissel is as follows:

> "The immense scope of this project, in the first instance, necessarily limits the number of potential EPC contractors. Thus the EPC pricing was based on an initial inquiry to three major contractors with coal engineering, procurement and construction experience. In fact, the results of this inquiry produced only one contractor with resources available in sufficient quantity to handle a project of this magnitude in the time frame required."

Immediately following that sentence, I make the statement that "FPL promptly undertook to negotiate a market-competitive agreement for the EPC services" and then proceed to explain FPL's approach to securing firm pricing while obtaining a market-competitive outcome. As I describe in my direct testimony, FPL clearly understood and considered the risk of increases in the actual capital cost of completing FGPP and placing the generating units into commercial operation. As a result, FPL took active steps to mitigate that risk and, in contrast to many other utilities around the country, having anticipated the need to secure firm pricing as a means to mitigate the risk of unexpected cost increases, took the appropriate steps to do so.

Q. **Does this conclude your rebuttal testimony?**

A. Yes.

CHAIRMAN EDGAR: All right. Thank you everyone, for your cooperation. And should we move to Mr. Kosky?

MR. ANDERSON: Yes, please.

CHAIRMAN EDGAR: Mr. Guest, does that work for you?

MR. ANDERSON: FPL would call as its next witness Mr. Ken Kosky.

CHAIRMAN EDGAR: Okay.

Thereupon,

KENNARD F. KOSKY

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

DIRECT EXAMINATION

BY MR. ANDERSON:

Q. Mr. Kosky, have you been sworn as a witness?

A. Yes, I have.

Q. Will you please tell us your name and your business address?

A. My name is Kennard Kosky, and my business address is 6241 Northwest 23rd Street, Gainesville, Florida, 32653.

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

A. I'm employed by Golder Associates, Inc., and I'm a principal in the Gainesville office.

Q. Have you prepared and caused to be filed 21 pages of prefiled direct testimony in this proceeding?

A. Yes, I have.

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

A. No, I do not.

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

A. Yes, they would.

MR. ANDERSON: FPL would ask that Mr. Kosky'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.

BY MR. ANDERSON:

Q. You're sponsoring some exhibits to your direct testimony?

A. Yes, I am.

Q. These are documents KFK-1 through KFK-7?

A. Yes, they are.

MR. ANDERSON: Madam Chairman, we would note that Mr. Kosky's exhibits have been premarked for identification as Numbers 39 through 45.

CHAIRMAN EDGAR: Thank you.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF KENNARD F. KOSKY

DOCKET NO. 07____-EI

JANUARY 29, 2007

Q. Please state your name and business address.

A. My name is Kennard F. Kosky and my business address is 6241 NW 23rd Street, Suite 500, Gainesville, Florida 32653.

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

A. I am employed by Golder Associates Inc., an engineering consulting firm specializing in ground engineering and environmental services. I am a Principal with the firm in the Gainesville office involved primarily in the environmental aspects of electric power plants.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science degree in engineering from Florida Atlantic University, and a Master of Science degree in environmental engineering from the University of Central Florida. I also completed one and half years of doctoral-level course work in the engineering Ph.D. program at the University of Florida.

Over the last 30 years my primary activities have involved the siting and licensing of electric power plants. I have worked on over 50,000 megawatts (MWs) of new and existing generation including conventional coal, oil and gas-fired steam generating units, combined cycle units, integrated coal gasification combined cycle (IGCC) units, simple cycle units, municipal solid waste (MSW) fired units, biomass-fired steam generating units, and diesel units. My primary technical activities have involved developing air emissions, evaluating air pollution control technologies and performing air quality impact evaluations of these facilities. A copy of my curriculum vitae is attached as Document No. KFK-1 to my testimony.

Q. Please describe any professional registrations or certifications that you hold in your field of expertise.

A. I am a registered Professional Engineer in mechanical engineering in the State of Florida. I have been practicing as a registered Professional Engineer since 1976.

Q. Could you please describe your responsibilities for FPL's Glades Power Park?

A. I had the overall responsibility for the preparation of the Site Certification Application (SCA) for the FPL Glades Power Park (FGPP). I signed and sealed the SCA as a Professional Engineer. I also had overall responsibility for the preparation of the Prevention of Significant Deterioration (PSD)/Air Construction Permit Application for FGPP and signed and sealed the application as a Professional Engineer.

Q. Are you sponsoring an exhibit in this case?

A. Yes, I am sponsoring an exhibit consisting of seven documents, KFK-1 through KFK-7, which is attached to my direct testimony. This exhibit provides some environmental comparisons of the FGPP and other power facilities and is based upon FGPP information that is currently being reviewed by the Florida Department of Environmental Protection (FDEP) and other state and regional environmental agencies which have regulatory jurisdiction concerning environmental, land use and other matters. The exhibit I am sponsoring consists of the following documents:

- Document No. KFK-1, curriculum vitae of Kennard F. Kosky
- Document No. KFK-2, a comparison of the air emissions of FGPP with existing generation technologies
- Document No. KFK-3, a comparison of the environmental impacts of FGPP with regulatory standards
- Document No. KFK-4, a comparison of the air emissions of FGPP with OUC Stanton Energy Center Unit B IGCC
- Document No. KFK-5, a comparison of the air emissions of FGPP with AEP Mountaineer IGCC
- Document No. KFK-6, a comparison of the mercury emissions of FGPP with EPA's New Source Performance Standards
- Document No. KFK-7, environmental compliance costs used in FGPP Economic Analysis

Q. Are you sponsoring any sections of the Need Study document?

A. Yes. I am sponsoring the following sections of the Need Study document: Section III.C. Environmental Controls, Section V. A. 3. Environmental Regulations and Section V. A. 4. a. (iii) Environmental Compliance Costs. Additionally, I sponsor Appendix F of the Need Study.

Q. What is the purpose of your testimony?

A. My understanding is that the Commission will consider and determine the need for FGPP pursuant to the utility laws and regulations that it is responsible for administering, which laws and regulations do not include environmental regulation. However, electric power plants constructed in Florida must comply with environmental regulations, and the costs of compliance are part of the project. Accordingly, the purpose of my testimony is to provide the Commission an overview of the key environmental aspects of FGPP and of the environmental regulatory uncertainties, both of which affect the cost of the project.

Based upon my training, experience and analysis conducted in relation to this project, my testimony reaches and supports the following key conclusions: (i) the selection of ultra-supercritical pulverized coal (USCPC) technology and environmental controls for FGPP not only meets, but exceeds the extensive environmental regulatory requirements; (ii) the technology selected for FGPP is the best available alternative from an environmental perspective consistent with maintaining fuel diversity; and (iii) the environmental compliance costs evaluated by FPL to meet future environmental requirements reflect an appropriate range of possible future costs, which fairly and reasonably takes into account uncertainty concerning future environmental requirements and costs.

Q. How is your testimony organized?

A. My testimony is divided into four sections. Section I provides an overview of the major environmental requirements for FGPP. Section II presents information on how FGPP's design will not only meet, but exceed these requirements. In this section, I will also provide environmental comparisons of FGPP with existing and other planned generation that demonstrates the favorable environmental characteristics of FGPP, while contributing to fuel diversity for customers in the timeframe required. Section III describes how FGPP, from an environmental perspective, is the best alternative to meet the fuel diversity need in FPL's system. Section IV describes the existing and possible future environmental requirements and their potential influence on future environmental compliance costs of FGPP. In this section, I will describe how these existing and possible future environmental costs were included in FPL's analysis.

SECTION I: ENVIRONMENTAL APPROVALS AND REQUIREMENTS

Q. What are the environmental approvals applicable to FGPP?

A. FGPP is required to obtain federal, state and regional environmental approvals and permits. The principal environmental approval is Site Certification under Florida's Power Plant Siting Act (PPSA). This is a comprehensive review of all environmental aspects of FGPP coordinated through the FDEP and involving all state and regional agencies with environmental responsibility and those agencies potentially affected by FGPP. This includes, but is not limited to, the FDEP, Florida Department of Community Affairs, Florida Department of Transportation, Florida Fish and Wildlife Conservation Commission, and the South Florida Water Management District (SFWMD). This comprehensive environmental review evaluates FGPP's environmental controls and determines compliance with applicable environmental standards. This ultimately leads to a comprehensive analysis by agencies and Conditions of Certification that set forth environmental requirements. FGPP will also require federal and federally delegated permits. This includes an approval by the U.S. Army Corp of Engineers for impacts to wetlands, a PSD/Air Construction Permit by the FDEP, and an Underground Injection Control Permit from the FDEP.

Q. Please summarize the major requirements for the environmental approvals of FGPP.

A. The major requirements include (i) minimizing impacts to wetlands and providing compensatory wetland mitigation; (ii) preventing adverse impacts to fish and wildlife; (iii) using the lowest quality water and minimizing impacts to surface and ground waters; (iv) installing Best Available Control Technology (BACT) from an environmental regulatory perspective; and (v) demonstrating that the air quality standards are met.

Q. What is BACT?

A. BACT is a technology standard administered by the FDEP pursuant to its PSD program that establishes an emission rate for all regulated pollutants requiring review. BACT cannot be any less stringent than any established emission standard for new facilities and is generally the lowest emission rate that is technically feasible for the specific type of facility. The FDEP ultimately establishes BACT based on the information in the PSD/Air Construction Permit Application and an evaluation of all recent similar projects in the U.S. For a coal-fired power generation facility, the air emissions controls are typically the most significant from a cost and environmental perspective.

Q. What is the current status of obtaining environmental approvals?

A. The SCA was submitted on December 22, 2006, and is currently under review. The permit applications for the PSD/Air Construction Permit, Underground Injection Control (UIC) Permit, and U.S. Army Corp of

Engineers wetlands permit were also submitted to the applicable agencies. These applications are currently under review.

Q. What are the general timeframes for approvals?

A. The site certification approval process has the longest statutory timeframe and generally takes about 14 months from submission of the application to approval by the Governor and Cabinet as the Siting Board. However, the approval of the site certification as well as individual permits can be challenged and delay approval. Challenges within the PPSA process or a challenge to the PSD/Air Construction Permit could delay approval due to discovery and extended hearings. The amount of time required for challenges is uncertain but historically has extended potential regulatory approvals by many months and even years.

SECTION II: FGPP COMPLIANCE PLANS

Q. What general features of FGPP serve to meet environmental requirements?

A. The FGPP site was selected at a location that provides the needed infrastructure for fuel delivery and which also minimizes environmental impacts. For example, the FGPP site is currently in agriculture that has previously impacted the environment. The site includes sufficient land area to provide mitigation for wetlands impacts. Water use effects will be minimized by using excess stormwater from SFWMD canals and lower-quality water from the Upper Floridan Aquifer. Water will be recycled as much as possible and released using UIC wells. FGPP will not have industrial water discharges to surface waters or groundwater that can impact the environment. Byproducts will be recycled to the greatest extent practicable. Byproducts that cannot be recycled will be placed in an area designed to have minimal impacts to the environment. Air emissions from FGPP will be minimized by use of the USCPC combustion technology selected by FPL and installation of state-of-the-art air pollution control equipment.

Q. **Please explain briefly the technology proposed for FGPP that will minimize air emissions.**

A. Minimizing air emissions involves two components. First, the higher energy efficiency of the USCPC technology reduces the amount of fuel required and, therefore, reduces the amount of air emissions per unit of energy produced. FGPP will utilize two USCPC fired steam generators with a heat rate much lower, meaning much more efficient, than nearly all coal-fired plants in the U.S. Second, each USCPC unit will be installed with proven air pollution control technology that, when combined together, will result in emissions that are among the lowest in the U.S. for similar new facilities and result in among the very lowest air quality impacts. The technology will include combustion controls to minimize formation of nitrogen oxides (NO_x), carbon monoxide (CO) and volatile organic compounds (VOCs), Selective Catalytic Reduction (SCR) for further minimizing NO_x emissions, Fabric Filter to minimize particulate matter (PM), a wet-limestone Flue Gas Desulfurization (FGD) to minimize emissions of acid gases such as sulfur dioxide (SO_2), and a wet Electrostatic Precipitator (ESP) to minimize particulate matter and aerosols. Together these controls also minimize trace metals air emissions including mercury. In addition, sorbent injection will be used to further enhance the removal of mercury in the air pollution control systems. As explained below, these technologies minimize air emissions to the greatest extent practicable, which results in minimal environmental impacts.

Q. **Based upon your training, experience and analysis, have you concluded whether the environmental controls planned for FGPP meet the requirements of BACT?**

A. Yes. I conclude that the environmental controls planned for FGPP meet the requirements of BACT. The emission rates proposed as BACT in the application submitted meets all the regulatory requirements of a BACT analysis as specified by the FDEP. Indeed the emission rates combined with the heat rate of FGPP are lower than most recently permitted pulverized coal-fired units in the U.S. Typical BACT emission limits are expressed in pounds of air pollutant for a normalized amount of heat input or pounds per million Btu. This measure does not take into account energy efficiency. Since FGPP will be an ultra super-critical steam generation unit, it is more efficient than conventional and many new units. Therefore, air emissions when taking into account energy efficiency will be lower. It should be noted that the FDEP has jurisdiction to determine that FGPP's environmental controls are BACT.

Q. How do the air emission rates for FGPP compare with recent generation projects in Florida?

A. I prepared Document No. KFK-2 to show a comparison of the emission rates established for some recent generation projects in Florida with those of FGPP. The air emissions rates are shown in pounds per net megawatt–hour (MW-hr) since, as I described previously, energy efficiency is an important criterion in minimizing air emissions. I have included on this chart an existing IGCC unit, a recent conventional pulverized coal unit, a recent Department of Energy (DOE) clean-coal circulating fluidized bed coal-fired unit and a natural gas-fired combined cycle unit. I included the latter for comparison since much of FPL's new generation over the last five years has been natural gas combined cycle. The air emissions presented in Document No. KFK-2 are the primary regulated air pollutants and include NO_x, SO_2, and PM. As shown in the document, the emissions of FGPP of NO_x and SO_2, while not as low as natural gas combined cycle, will be much lower than recent coal projects. Of course, adding additional natural gas generation would not result in reducing the use of natural gas or in diversifying fuel sources for FPL's customers. For PM, emissions of all technologies provide low air emissions rates with natural gas combined cycle providing the lowest.

Q. How will the emission rates proposed for FGPP affect air quality?

A. The emissions rates will only minimally affect Florida's air quality. In fact, the air quality impacts, which are the most important aspect in evaluating air emissions, will not only meet all applicable requirements, but will not degrade the air. I prepared Document No. KFK-3 to show the maximum impacts of FGPP with respect to Florida's ambient air quality standards and the PSD Increments. The ambient air quality standards were established to protect the general public with an adequate margin of safety, while the PSD Increments protect the air from degradation. As shown, the maximum impacts are a very small fraction of the regulatory standards.

Q. **How do the emissions of FGPP compare with those of new IGCC units?**

A. I prepared two documents. Document No. KFK-4 shows the emission rates of FGPP compared with the proposed Orlando Utilities Commission's (OUC) Stanton Unit B IGCC unit. As shown in the chart, the emission rates for FGPP will be lower for NO_x and higher for SO_2. The OUC unit is a nominal 270 MW. Document No. KFK-5 shows a comparison of FGPP with the nominal 500-MW IGCC Mountaineer project being proposed by American Electric Power. As shown in this document, the rates for FGPP will be lower for NO_x and higher for SO_2. It should be noted that the emission rates shown in Document No. KFK-5 are very low, and as I have stated earlier, FGPP will fully comply with all air quality standards.

Q. **Will the emission rates of mercury from FGPP meet or be less than regulatory standards?**

A. Yes. The emission rates of mercury from FGPP will be about one-half of the latest and most stringent mercury emission standard recently established by the Environmental Protection Agency (EPA). I have prepared Document No.

KFK-6, which shows the new EPA standard and the maximum emissions proposed for FGPP.

Q. Does FPL's environmental compliance plan for FGPP meet, or exceed, the applicable environmental requirements?

A. Yes. FPL's environmental compliance plan for FGPP will meet all applicable environmental requirements and standards. Indeed, many of the environmental designs will exceed (in this case I mean be better than), the requirements and standards.

Q. How does FPL's emission rates compare to other utilities?

A. FPL's overall emission profile is low compared to all other utilities in the US. In a study conducted by the National Resource Defense Council, FPL emission rates in lb/MW-hour for SO_2, NO_x and CO_2 were found to be one of the lowest in the country for fossil-fuel fired generation.

Q. Will the emissions of FGPP change FPL's emission profile?

A. No. FPL's emissions profile will not change and will likely be lower when FGPP begins operation. For example, the NO_x emissions from FGPP on a lb/MW-hour basis are four times lower than FPL's already low utility-wide NO_x emission rate for fossil generation. In this case, the addition of FGPP will improve FPL's low emissions profile. In fact, in 2015, FPL's rate of CO_2 emissions with FGPP would be trending downwards. The average rate of CO_2 emissions for the period 2015 through 2020 is expected to be 17.4% lower than the period from 2000 through 2005.

SECTION III: ENVIRONMENTAL CONSIDERATIONS OF ALTERNATIVE GENERATION

Q. Are you familiar with the environmental aspects of possible generation alternatives that are potentially available to provide FPL's generation requirements in the 2013 and 2014 timeframe?

A. Yes. Over the last several years I have been involved in the environmental licensing of over 5,000 MW of natural gas-fired combined cycle plants. I have been involved in the environmental feasibility and licensing of IGCC since 1990. I have considerable experience, starting in the late 1970s, in licensing conventional pulverized coal-fired facilities.

Q. How does the design of FGPP compare with the other potential generation alternatives from an environmental perspective?

A. As I presented in Document No. KFK-2, a natural gas combined cycle plant would have environmental advantages over other available technologies. Natural gas is the cleanest combusting fossil fuel and can be efficiently used in a combined cycle facility. While these facilities can be constructed in a size to meet FPL's generation requirements for 2013 through 2014, the continued use of natural gas does not contribute to fuel diversity in FPL's system. The use of conventional pulverized coal-fired technology, while reliable with proven pollution control technology, is less efficient than the USCPC technology being proposed for FGPP. FGPP will combine proven, demonstrated and reliable air pollution control technologies that will minimize environmental impacts with the highly efficient USCPC technology. As I have shown in Document Nos. KFK-2 and 3, the air emissions will be low and the environmental impacts will be minimal. The use of IGCC technology, as I have shown in Document Nos. KFK-4 and 5, does not have distinct environmental advantages over USCPC technology. Moreover, there are no existing or planned IGCC units or plants anywhere near the approximately 2,300 MW of generation capacity needed by FPL to serve its customers in the 2012 through 2015 timeframe. For these reasons, FPL's selection of USCPC technology is the correct one from an environmental perspective, taking into account the need for reliable production of large amounts of power from a fuel-diverse generation source beginning in the 2013 through 2014 timeframe.

Q. **In your opinion, is FGPP the best available environmental choice to achieve fuel diversity in the 2013 to 2014 timeframe?**

A. Yes. My opinion is based on the fact that FGPP will utilize available and demonstrated generation and environmental control technologies. The environmental controls have been proven to reduce air emissions resulting in minimal potential environmental impacts.

SECTION IV: FUTURE ENVIRONMENTAL CONSIDERATIONS

Q. What additional future environmental requirements will potentially be applicable to FGPP?

A. The EPA promulgated two major environmental regulations that will be applicable to FGPP. These regulations are EPA's Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR). CAIR establishes state limits on annual and seasonal emissions on NO_x and annual emissions of SO_2. The limits apply to 25 states, primarily in the eastern U.S., and the District of Columbia (DC). The limits were established in two timeframes: NO_x - 2009 through 2014; 2015 and beyond, and SO_2 – 2010 through 2014; 2015 and beyond. EPA's rule includes a cap-and-trade system that allows affected facilities to meet the requirements through either the addition of control technologies or acquisition of allowances through a market based system. The cap-and-trade system in EPA's CAIR regulations is similar to the successful Acid Rain Program referred to as Title IV that was initially developed through the 1990 amendments of the Clean Air Act. In implementing CAIR, the EPA allowed states to utilize model rules in implementing CAIR or develop specific regulations to meet the requirements of CAIR. The FDEP has adopted the EPA model rule that would allow the use of the national cap-and-trade system.

EPA's CAMR regulations have two components. First, the EPA issued New Source Performance Standards for the mercury emissions from new sources like FGPP. As I have shown in Document No. KFK–6, FGPP will have a mercury emission rate that is about one-half of the new EPA standards. Second, EPA's CAMR established mercury emission limits on states, and similar to CAIR, allows for a cap-and-trade program to meet requirements. The state mercury emission limits start in 2010 and are reduced in 2018. FDEP has established a hybrid rule that is more stringent than the EPA rule in the 2010 through 2017 timeframe, and the EPA model rule in 2018. Florida allows the use of the cap-and-trade program.

Q. How will EPA's CAIR and CAMR regulations influence FGPP?

A. FPL will be required to hold allowances for the actual emissions from FGPP of NO_x, SO_2, and mercury. These allowances would have a potential economic impact, since allowances must be obtained through a state pool or the cap-and-trade system.

Q. Did FPL consider the potential economic impacts of CAIR and CAMR?

A. Yes. FPL utilized potential costs based on projections developed through a comprehensive analysis of multiple factors involving air pollution control costs, fuel utilization and market factors. These projections, while necessarily having a range of uncertainty, are based on air pollution control costs and experience from the Acid Rain Program (Title IV). The control technologies for NO_x and SO_2 are well established and their cost can be estimated with reasonable accuracy. The Acid Rain Program has been operating for a decade and while there have been fluctuations in allowance costs, past projections have been within the expected range. The cost estimates for mercury were developed in a similar manner and also considered the fact that some states will implement CAMR outside the model cap-and-trade system.

Q. Are there any laws regulating CO_2?

A. No, there are no current rules regulating CO_2.

Q. Did FPL consider possible CO_2 regulations in the economic analysis of FGPP? If so, how?

A. Although there are no current laws regulating emissions of CO_2, FPL considered the potential future regulation of CO_2 using projections developed from federal legislative initiatives and the basic framework of the cap-and-trade system. Over the last several years there have been federal legislative initiatives that have proposed different forms of CO_2 regulation based on the cap-and-trade system. These initiatives have included both multi-sector and electric sector regulation with variable reductions of CO_2 emissions. These federal legislative initiatives formed the bounds for the potential costs that may occur in the future.

Q. Please explain the range of compliance costs for the CAIR, CAMR and potential CO_2 regulations that were included in the economic analysis of FGPP.

A. I prepared Document No. KFK-7, which shows the allowance costs in nominal dollars used in the economic analyses for FGPP. The compliance costs under the cap-and-trade system are based on the cost of allowances, which is multiplied by the amount of allowances required for FGPP for the specific pollutant. The allowance costs for NO_x, SO_2, mercury, and CO_2 are shown in Document No. KFK-7. The allowance costs were based on information from ICF International in a report titled "U.S. Emission & Fuel Markets Outlook, 2006 edition." The ICF report provides allowance cost forecasts that are based on integrated modeling of the electric, fuel and environmental markets in the U.S. Four allowance cost scenarios were used in the economic analysis of FGPP. These scenarios were: Scenario A – Allowance Costs for SO_2, NO_x, and mercury, referred to as 3P (P in this case means "Pollutant"); Scenario B – Allowance Costs for SO_2, NO_x, and mercury, with low CO_2 allowance costs, referred to as 4P-mild; Scenario C – Allowance Costs for SO_2, NO_x and mercury, with moderate CO_2 allowance costs, referred to as 4P-medium; and Scenario D – Allowance Costs for SO_2, NO_x, and mercury, with high CO_2 allowance costs, referred to as 4P-high. The range of low, medium and high costs of CO_2 allowances that were used are consistent with current legislative proposals being considered by Congress and reflect the appropriate range of potential future allowance costs for CO_2. The allocations of SO_2, NO_x, and mercury allowances were based on the CAIR and CAMR rules developed by the FDEP. For CO_2 it was assumed that 100 percent of the required allowances would be purchased under a cap-and-trade system similar to an auction.

Q. In your opinion, are the allowance costs shown in Document No. KFK-7 and used in FPL's economic analysis, reasonable and appropriate future environmental compliance costs?

A. Yes. My opinion is based upon my training and experience, and my in-depth review of FPL's economic analysis. I concluded that FPL considered reasonable and appropriate environmental costs in the ranges that are predicted to occur in the future. While there is, of course, considerable uncertainty on what will actually be required in the future, the environmental costs utilized were developed using known regulations for limiting NO_x, SO_2 and mercury, a range of legislative initiatives that are being considered for the regulation of CO_2, environmental control costs that can be estimated with reasonable accuracy, and market factors established by the cap-and-trade program.

Q. Please summarize your testimony.

A. My testimony provides an overview of the key environmental aspects of FGPP. My testimony demonstrates that the technologies selected for FGPP that include USCPC technology and state-of-the-art air pollution control equipment will meet or exceed the environmental regulatory requirements. FGPP will have minimal environmental impacts. As a result, FGPP is the best available alternative to maintain fuel diversity from an environmental perspective. Future environmental regulations require consideration of compliance costs. Cap-and-trade regulations required by the EPA have been adopted by the FDEP for the future regulation of SO_2, NO_x and mercury emissions. These regulations will require FPL to hold allowances with associated costs for these pollutants. Regulation of CO_2 emissions has not been implemented but is likely in the future. Together, the existing and potential future environmental regulations have considerable uncertainty for associated compliance costs. To address this uncertainty, a range of compliance cost developed from integrated modeling of the electric, fuel and environmental markets in the U.S. was used in the economic analyses conducted for FGPP. The compliance costs used in the economic analysis were an appropriate range of potential costs that reasonably encompasses the uncertainty in future environmental compliance costs for FGPP.

Q. Does this conclude your direct testimony?

A. Yes.

BY MR. ANDERSON:

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

A. Yes, I do.

Q. Would you please provide it at this time.

A. Good afternoon, Madam Chairman and members of the Commission. My name is Kennard Kosky.

Over the past 30 years, I've been an engineer responsible for the evaluating and environmental aspects of electric power generating projects. I've performed projects in more than 28 states and 22 foreign countries and have been involved in the construction and/or operation of over 100,000 megawatts of electric generating capacity.

Concerning FP&L's project in this proceeding, I signed and sealed the site certification application for the FPL Glades Power Park, FGPP, which is the subject of this proceeding. I'm an independent professional engineer responsible for directing and managing all environmental compliance aspects of the project.

My role today is to provide assurance that FGPP will be environmentally compliant and that the expected costs of environmental compliance have been included and properly considered by FPL.

Here are some key points concerning FGPP. FGPP will utilize highly efficient generating technology combined with a suite of state-of-the-art air pollution control equipment. The FGPP environmental controls are based on proven and demonstrated technologies and will result in the lowest air emission rates of any pulverized coal plant in Florida, as well as one of the lowest emission rates in the United States. FGPP will also result in minimal impacts to the environment.

Concerning FGPP's environmental compliance, I have shown in document number KFK-3 the maximum impacts of FGPP compared to the regulatory standards. For ease of reference today, I prepared a separate large chart for each of the four emissions on document number KFK-3.

Let's look at the first chart, which is for sulfur dioxide. The blue bar on the left of the chart shows the ambient air quality standards for sulfur dioxide. The ambient air quality standards were developed by the United States Environmental Protection Agency and adopted by the State of Florida to protect public health and welfare and the environment with an adequate margin of safety. The middle bar shown as a mustard color represents what is called the prevention of significant deterioration increments or PSD increments. The PSD increments apply to new facilities like FGPP and to modified facilities to protect air from degradation. The next bar on the right shows the maximum sulfur dioxide impacts of FGPP, also shown by the arrow.

As you can see, the maximum impact of FGPP is much lower than the environmental standards that will apply to the plant. In fact, the maximum FGPP impacts are more than 50 times lower than the ambient air quality standards to protect public health and more than 17 times lower than the regulatory standards to protect air from degradation.

The second chart shows the maximum impacts for nitrogen dioxide. Again, you can see the blue bar for the ambient air quality standard, and the next bar, the mustard color, for the PSD increment. The right bar for FGPP is much lower than the standards for nitrogen dioxide. In this case, FGPP's maximum impacts are 145 times less than the public health standard and 36 times less than the degradation standard.

Shown on the next chart are the maximum impacts for particulate matter. Again, the right-hand bars for FGPP with the arrow are much lower than the regulatory standards for particulate matter that protect health and air quality.

The final chart shows the very low impacts of

FGPP for carbon monoxide. For this air emission as well as others, the maximum impacts of FGPP are well below the standards to protect public health, welfare, and the environment, and those standards that ensure that our air remains clean.

I've also evaluated the maximum impacts from mercury, which are so small as to be measurable. Those results are in a chart I submitted in my rebuttal testimony, and I wish to review those at that stage of the hearing.

In conclusion, I thought it might be of benefit to the Commission to know that taken together, the efficiency of the ultra-supercritical technology, the state-of-the-art environmental controls, proposed emission levels, and the environmental impacts, FGPP will be the cleanest solid fuel fired power plant that I've seen in my career and that I'm aware of in the electric utility industry. Thank you.

MR. ANDERSON: Mr. Kosky is available for cross-examination.

CHAIRMAN EDGAR: Mr. Beck.

MR. BECK: Thank you, Madam Chairman.

CROSS-EXAMINATION

BY MR. BECK:

Q. Good evening, Mr. Kosky.

A. Good evening.
Q. Could you turn to your Exhibit 7, page 5 of 5?
A. Sure.
Q. That exhibit shows projected environmental compliance costs for carbon taxes, does it not?
A. It shows environmental compliance costs for actually four pollutants, sulfur dioxide, nitrogen oxides, mercury, and carbon dioxide.
Q. But page 5 of 5 is just carbon dioxide environmental compliance costs, is it not?
A. Yes, page 5 of 5 are.
Q. And you have -- four different scenarios are included in your graph; is that right?
A. Four different scenarios of potential costs are presented; that's correct.
Q. And the A scenario is the scenario where there will be no carbon taxes or cap-and-trade system in place at any time through the life of the plants; is that right?
A. Yes, in that scenario, there is no carbon tax.
Q. And so the A scenario simply shows a straight line along the zero axis; is that right?
A. That's correct.
Q. Okay. And then the B scenario is the low carbon tax; is that right? And when I say carbon tax, I

include cap and trade in that.

A. Cap and trade, we called it a mild cost of CO_2 credits or allowances.

Q. And what is the C scenario?

A. The C scenario was a moderate.

Q. And the D?

A. And D was the more stringent.

Q. And these scenarios were provided to you by a firm named ICF International; is that correct?

A. Yes. These were developed by ICF International in a report that they prepared related to the allowances of all the pollutants that I had mentioned, sulfur dioxide, nitrogen oxides, mercury, which are currently regulated or will be regulated. There are regulations for those, and potential costs for carbon dioxide.

Q. And FPL has a witness coming on later who will be able to talk about the forecasts provided by ICF, do you not?

A. Yes. Mr. Rose will be presenting more detail on their specific analysis.

MR. BECK: Thank you. That's all I have.

CHAIRMAN EDGAR: Mr. Guest.

MR. GUEST: Just a few questions to clarify.

CROSS-EXAMINATION

BY MR. GUEST:

Q. You don't have a Clean Air Act permit, do you, for this plant?

A. No. That's currently under review by the Department of Environmental Protection.

Q. They've actually -- also, the Department has asked you to consider the IGCC option in connection with air pollution issues, has it not?

A. I don't think that's correct. They had a question related to information that Florida Power & Light developed in its proposal for the ultra-supercritical technology. And in fact, Mr. Hicks testified as to that particular report, and that information was submitted to the Florida Department of Environmental Protection.

Q. The superintendent of the Everglades National Park has objected strenuously to the issuance of an air permit for this facility, has he not?

A. That's not correct.

Q. Well, please correct me.

A. I'll be happy to. The National Park Service has provided actually two comment letters to the Florida Department of Environmental Protection basically asking for more information. In the first letter, they had particular concerns, which we addressed to the Florida Department of Environmental Protection in what's called their completeness determination. They reviewed that information. They had some additional questions, which they supplied in another letter, and we are currently meeting with the National Park Service to address their technical concerns regarding any analyses or impacts that might occur.

Q. So are you saying that the status of things right now is that the National Park Service, that the superintendent of the Everglades National Park is neutral or in favor of this plant?

A. Well, I think that they right now are evaluating information. They justifiably had some interest in the potential impacts and expressed those twice, and we provided information, for example, in the first letter, in which we fully addressed many of their concerns. In fact, their second letter was essentially acknowledging that now they understood some of the things about the project. So it's an ongoing process.

Q. I notice that you don't have anything about mercury here in the exhibits that you've handed out here. Is there a reason for that?

A. In the exhibits that I handed out?

Q. Yes. You talk about some parameters, you know, sulfur dioxide, small particles, nitrogen dioxide, carbon monoxide. You didn't include mercury.

A. Mercury does not have an ambient air quality standard, nor does it have a degradation or clean air standard. However, in my direct testimony, I provided document number KFK-6, which showed the emission rates of FGPP compared to the latest new source performance standards that were promulgated by EPA as of June 2006. In fact, the emission rate proposed by FGPP is one half the more recent standard that EPA had promulgated.

In my rebuttal testimony, I do present information more detailed on mercury.

CHAIRMAN EDGAR: Mr. Guest, can I jump in with a question?

MR. GUEST: Sure.

CHAIRMAN EDGAR: Referring back to a question or so ago that Mr. Guest was asking, I guess, Mr. Kosky, in your experience or opinion, does a superintendent of a national park have the authority to speak on behalf of the National Park Service as far as comments on a proposed permit?

THE WITNESS: Yes. They are the federal land manager of the class 1 area, the Everglades National Park, and they evaluate what's called the air quality related values of the park. Typically it's the impacts on sensitive species and deposition. We supplied a considerable amount of information to the park, as well as other analyses, and in fact, that's still ongoing related to the review of the air construction permit by the Florida Department of Environmental Protection.

CHAIRMAN EDGAR: And so -- and I'm just trying to refresh my memory as to the process, the federal agency review process of a proposed permit to be issued by the environmental state agency. Would the superintendent then of a national park that has the potential to be impacted, in this case, Everglades National Park, would it be the superintendent that would be issuing comments, the agency review comments?

THE WITNESS: He would be reviewing comments to the Florida Department of Environmental Protection. It may also be through the Department of Interior.

CHAIRMAN EDGAR: Thank you.

MR. GUEST: Thank you for that clarification.

BY MR. GUEST:

Q. So you're aware, are you not, that a number of parties have joined the issue in the Power Plant Siting Act process that goes before the administrative law judge and that the matter of compliance with the Clean Air Act is one of the issues in play?

A. Yes, I'm aware of that.

MR. GUEST: No further questions.

CHAIRMAN EDGAR: Mr. Krasowski, do you have questions on cross?

MR. KRASOWSKI: Yes. Thank you.

CROSS-EXAMINATION

BY MR. KRASOWSKI:

Q. Hi, Mr. Kosky. I happen to have that letter from the Park Service here, and they express concern and do ask questions about IGCC.

But let me ask you, this whole issue of environmentalism, do I understand correctly that you're here today to speak to how this project will comply with existing rules as far as emissions, EPA rules?

A. Emissions as well as the ambient air quality standards, the PSD increments. The foundation of this starts in 1970 with the Clean Air Act Amendments, and that has been the foundation of air quality management, as it were, in the United States since that time.

Q. But you're not here on the broader scale, comprehensive commentary on environmental impacts as far as -- you've avoided mercury as an issue for the reasons you've stated, but there's mercury in the fish, and this contributes to more mercury, this project, and then also the global warming is a big environmental -- do you believe in global warming?

MR. ANDERSON: Chairman Edgar, we have multiple questions and a mischaracterization of avoiding mercury, so perhaps if we were to --

MR. KRASOWSKI: Apologies for doing that. I'll try to clear that up.

BY MR. KRASOWSKI:

Q. Okay. So maybe you didn't avoid mercury, but you explained. You explained yourself that mercury is not included in your handout because it isn't under the same -- well, could you restate that? Why isn't mercury included in your handout?

A. Well, we submitted a site certification application that has environmental impacts, evaluations on mercury. We've provided additional information. It's probably close to three or four feet deep.

My purpose here today was really to provide the Commission information relative to the basic structure of environmental controls for FGPP that are included to comply with the environmental requirements, as well as to look at the regulations that are currently adopted by the DEP for mercury, sulfur dioxide, and nitrogen dioxide, as well as the potential for any future regulation, which it hasn't been so far, of carbon dioxide.

Q. Okay. I guess I just wanted to clear up the point that your comments here are bracketed by the relevancy of this body's relationship to the environmental impacts, economic environmental impacts of the project, not environmental concerns.

A. Correct. The venue for that would be through the Florida Department of Environmental Protection, which will have a public hearing related to those aspects. My purpose today was to provide the Commission with a overview of the environmental controls, as well as in the charts that I've shown, the very low impacts, for which we haven't had any concern or comments related to those from DEP of the project.

Q. But you're not here to speak of the inadequacy of these standards and controls in terms of their impact on global climate change; is that a correct statement?

A. Well, first, there's --

MR. ANDERSON: I would just interpose that that's way beyond the scope of our hearing tonight, and we're getting late.

MR. KRASOWSKI: Madam Chair --

CHAIRMAN EDGAR: Mr. Krasowski.

MR. KRASOWSKI: Excuse me for interrupting. You had something to say.

CHAIRMAN EDGAR: You may. I was going to comment that there are numerous hearings ongoing around town, the state, the nation, and the world on global warming, and we're probably not going to solve it this evening. And I didn't mean that to be disrespectful, by the way, but we're not going to solve it this evening. So I would ask you to keep your questions pointed to the testimony of this witness.

MR. KRASOWSKI: That was my final question, and all I was hoping to make clear was that -- was to ask Mr. Kosky if he would agree that his testimony here today did not go outside of the purview of the economic environmental points to this body and did not even attempt to address the broader issue of what might be the inadequacies of these standards to address broader environmental issues.

BY MR. KRASOWSKI:

Q. Is that correct, Mr. Kosky? You're not here to speak about -- did I do it again? Okay. Well, I'll end there then.

CHAIRMAN EDGAR: You did.

MR. KRASOWSKI: I'll stop.

CHAIRMAN EDGAR: However, with the clarification, I'm going to allow the witness to respond.

A. Well, first, my testimony did address potential regulations of CO_2, and in fact, in my rebuttal testimony, I provided more information to the Commission.

The one thing, as testified by Mr. Hicks, as well as my opinion, is the fact that FGPP does address CO_2 or climate change potential by the efficiency. It will be the most efficient power plant in the country.

As far as the other particular pollutants that I've shown on the charts, these particular standards are developed through peer review, independent, by EPA, established initially in 1970. They rereview these standards to protect health and welfare. So there isn't any inadequacy related to the air standards that I'm presenting. These are actually evaluated by EPA on a regular basis, and in fact, made more stringent as necessary. In fact, there are some more stringent standards being developed and have been developed for pollutants all the time.

MR. KRASOWSKI: Thank you, Mr. Kosky.

CHAIRMAN EDGAR: Thank you. And I'll note that Mr. Kosky will be back, so you can maybe try again, Mr. Krasowski.

Are there questions from staff?

MS. BRUBAKER: None from staff.

CHAIRMAN EDGAR: None from staff.

Mr. Anderson.

MR. ANDERSON: We have no redirect. We would offer Exhibits 39 to 45. If we could pause for a second.

Please pardon my confusion. Nothing about redirect, just some points of order. We wanted to make sure that we offered Exhibits 39 to 45, which are Mr. Kosky's exhibits.

CHAIRMAN EDGAR: And that's what we would be doing next.

MR. ANDERSON: Exactly. The other thing was, we just wanted to confirm that Mr. Yeager's direct and rebuttal was entered into record. I know I offered the exhibits and they were admitted, but with the prior witness, we wanted to make sure that that was entered in.

CHAIRMAN EDGAR: Okay. I think that we did that. Ms. Brubaker?

MS. BRUBAKER: Yes, that's my recall also.

MR. ANDERSON: And those were the points.

CHAIRMAN EDGAR: That's fine. That's fine.

MR. ANDERSON: Thank you very much.

CHAIRMAN EDGAR: It's late. I do not mind being asked to double-check.

Okay. So Exhibits 39 through 45 will be entered into the record.

(Exhibits 39 through 45 admitted into the record.)

CHAIRMAN EDGAR: And, Mr. Kosky, you are excused until we will see you again for rebuttal. Thank you very much.

And I think we can keep going with one more witness if --

MR. ANDERSON: Good.

CHAIRMAN EDGAR: -- everybody is up to it.

MR. GUEST: Your Honor, I am flat dog tired. I truly am.

CHAIRMAN EDGAR: I understand. Does that mean you would like a break, or are you offering that we adjourn for the evening?

MR. GUEST: It would be my hope that you might do that, adjourn for the evening, like right now.

CHAIRMAN EDGAR: Note that one of the reasons we were pushing forward was to make sure that we got to your witnesses tomorrow. However, realizing that we were able to stipulate Mr. Yeager, and then we have Mr. Sim. The next four witnesses, as pointed out earlier, will be stipulated, have been agreed to be stipulated, and their testimony will be entered in when we come to that. That then leaves just Mr. Furman and Mr. Plunkett, and then Mr. Schlissel's testimony and exhibits to be entered. And I guess this is more for my benefit than anybody else's to see where we are. So is there -- Mr. Litchfield.

MR. LITCHFIELD: Madam Chairman, I was going to note that I think if we were to take Mr. Sim, we stand a reasonable chance of finishing tomorrow. I think if we don't take him up, those chances diminish significantly.

My understanding -- and maybe it has changed, but my understanding was that counsel for the Sierra Club had few, if any, questions for Mr. Sim on his direct testimony, but they had some on his rebuttal. He's only going to be sponsoring or addressing his direct testimony right now. So depending on the number of questions from other parties, we may not talking about very much time in order to get through Mr. Sim this evening, at least on his direct.

MR. KRASOWSKI: Madam Chair --

CHAIRMAN EDGAR: Hold on. Yes, Ms. Brubaker.

MS. BRUBAKER: I would like to note that we do have some cross for Mr. Sim. Depending on how quickly we can get through it, I would estimate between 20 and 30 minutes, however. So --

CHAIRMAN EDGAR: Well, there you have it.

MS. BRUBAKER: I don't wish to be the sticky thorn, but I didn't want to be ignored either.

CHAIRMAN EDGAR: That's not a label that I would use, Ms. Brubaker.

Okay. Yes. Who else? Mr. Krasowski, yes, sir.

MR. KRASOWSKI: I just wanted to mention that Ms. Brubaker won't be the only sticky thorn. I as well had some questions of Mr. Sim, but don't want to keep the gentlemen up any --

CHAIRMAN EDGAR: I understand. I understand. I appreciate you working with us.

Mr. Litchfield, nice try. Thank you.

Okay. We will go on break. I know it's been a long day, and we will being back at 9:30 in the morning. We are done for the day.

(Proceedings recessed at 6:10 p.m.)

(Transcript follows in sequence in Volume 8.)

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 862 through 1084 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 26th day of April, 2007.

Mary Allen Neel

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