BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. UNDOCKETED

In the Matter of

REVIEW OF TEN-YEAR SITE
PLANS OF ELECTRIC UTILITIES
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PROCEEDINGS: WORKSHOP

BEFORE: CHAIRMAN LILA A. JABER
COMMISSIONER J. TERRY DEASON
COMMISSIONER BRAULIO L. BAEZ
COMMISSIONER RUDOLPH "RUDY" BRADLEY
COMMISSIONER CHARLES M. DAVIDSON

DATE: Wednesday, August 6, 2003

TIME: Commenced at 9:37 a.m.
Concluded at 3:15 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: LINDA BOLES, RPR
TRICIA DeMARTE, RPR
Official FPSC Reporters

IN ATTENDANCE:

PAUL H. ELWING, LEONARDO GREEN and LINDA CAMPBELL, representing the Florida Reliability Coordinating Council, Inc.

BEN CRISP, representing Progress Energy Florida, Inc.

STEVE SCROGGS, representing Florida Power & Light.

MIKE MARLER and HOMER BELL, representing Gulf Power Company.

WILLIAM SMOTHERMAN, representing Tampa Electric Company.

WILLIAM MAY, representing Gainesville Regional Utilities.

DALE ISLEY, representing JEA.

MYRON ROLLINS, representing OUC.

PAUL CLARK, representing the City of Tallahassee.

LANE MAHAFFEY and QUANG TANG, representing Seminole Electric Cooperative, Inc.

JOHN McWHIRTER, consumer representative.

JON MOYLE, JR., Moyle, Flanigan, Katz, Raymond & Sheehan, P.A.

MICHAEL GREEN, representing the independent power producers in Florida.

COCHRAN KEATING and MIKE HAFF, representing the Florida Public Service Commission.

P R O C E E D I N G S

CHAIRMAN JABER: Good morning. Let's go ahead and get started with the workshop.

I want to start by welcoming everyone's participation this morning. This is a very, very informative workshop that we have each year at the Florida Public Service Commission that results in a review of the ten-year site plans that ultimately come to our internal affairs for review. But it's a good opportunity for dialogue and questions from the Commissioners and the parties to each other and staff to the participants. So we welcome your being here.

It's my understanding from staff that there's a notice that needs to be read and then an agreed upon order for presentations, we'll discuss that in a minute, but let me let staff read the notice.

MR. KEATING: Okay. Pursuant to notice issued July 21st, 2003, this time and place have been set for a Commission workshop in the undocketed matter of the review of ten-year site plans of electric utilities.

CHAIRMAN JABER: Mr. Keating, it's -- what we do each year, rather than take appearances, is just run through the order of presentations and let people make appearances as they come up to speak. And I would ask the parties, if you have handouts for your presentation, let's make sure we get those prior to your presentation. I'd ask that answers be concise, your presentations be precise, we avoid duplication and get this, get through this as quickly but as efficiently as possible.

It's also my understanding that you've agreed upon an order for the presentations.

MR. HAFF: That's correct.

CHAIRMAN JABER: Okay. Well, what I'd like to do, Mr. Haff, is just turn it over to you and Mr. Keating and you can help us get started.

MR. HAFF: Okay. As the Chairman said, we're going to follow the order that was in the notice, and the first presentation today will be given by representatives of Florida Reliability Coordinating Council.

MR. ELWING: Good morning, Commissioners. Thank you for the opportunity to come and speak to you this morning on the reliability of the State of Florida from an electric utility perspective.

My name is Paul Elwing. I'm with Lakeland Electric, but I'm here representing the FRCC this morning in the capability of the -- I am the chair of what's called the Reliability Working Group this year.

CHAIRMAN JABER: Can I ask you to spell your last name for me?

And, Commissioners, I neglected to inform you that the presentations you'll be able to see -- in addition to the handouts, you can see them on the computer in front of you.

Spell your last name.

MR. ELWING: Yes. My last name is spelled E-L-W-I-N-G.

CHAIRMAN JABER: Thank you.

MR. ELWING: In overview, I'm going to be speaking on the 2003 load and resource plan and reliability assessment. We also have Mr. Leo Green from Florida Power & Light, who will be speaking on load forecasting issues in particular, and Ms. Linda Campbell from FRCC staff, who will be speaking on natural gas electric interdependency issues.

Looking at the chart in front of you, Page Number 3 in your packet, we see continued growth taking place in Florida. And our average annual growth rate for summer is projected to be 2.52 percent and for winter 2.57 percent, and this is fairly consistent with what we have seen in the past. Growth rates are just a little bit higher than they were projected to be for last year, but no significant differences there.

The FRCC firm peak demand forecast, likewise, you can, you can see there a comparison between 2002 and 2003. As I said, the growth rate for the 2003 forecast is slightly higher than it was for 2002, and so thus you see the 2003 number starting to pull away in the later years.

Winter peak demand is following the same trend.

2003's forecast is just slightly higher than 2002's.

If you have any questions anywhere along the line, please don't hesitate to ask.

This next slide is cumulative capacity additions from the aggregate load and resource plan from the utilities, and what we're seeing over the ten-year period, by the time you get out to 2012, accumulative addition of 16,013 new megawatts of capacity in the State of Florida. And that capacity rating is based on summer ratings.

Looking at capacity mix by fuel type --

COMMISSIONER DEASON: I'm sorry. Would you back up for just a moment, please?

MR. ELWING: Sure.

COMMISSIONER DEASON: The bar graph there, the existing capacity seems to stay stable. Am I to conclude that there is -- it's not anticipated there's going to be any retirements, or how should I -- what should I take from that?

MR. ELWING: There are no significant amount of retirements being proposed by the utilities. Yes, there are some retirements in the plan, but as a percentage of the total capacity, total existing installed capacity in the State of Florida those are not showing up to be enough to make a difference on the graph or make a visual difference.

COMMISSIONER DEASON: Thank you.

MR. ELWING: The capacity mix by fuel type, we've got the current year 2003 compared with the horizon year of 2012, and the major change that you can see there is the increase in capacity in the area of gas-fired generation. The forecast for 2003 showed gas-fired generation to be approximately 37 percent of the capacity in the State of Florida. By 2012 that's forecasted to be approximately 52 percent of the capacity on a megawatt basis.

Likewise, looking at it from an energy perspective, we see again the biggest change is the addition of gas coming into the state. Gas generation on an energy basis for 2003 is forecasted to be approximately 23 percent of the state's energy need. By 2012 that's forecasted to be approximately 48 percent of the state's energy need is supplied by gas.

CHAIRMAN JABER: Mr. Elwing, is the reduction in nuclear directly related to the increase in reliance on gas?

MR. ELWING: Yes, ma'am, it is. There's no slated nuclear or coal retirements in the utilities' plans, and so that percentage is just shrinking by virtue of the fact that the amount of gas capacity is increasing.

CHAIRMAN JABER: Now nuclear -- I'm sorry. Go ahead, Commissioner Bradley.

COMMISSIONER BRADLEY: Go ahead.

CHAIRMAN JABER: Nuclear is the, I guess it's all relative, but the cheapest form of fuel in terms of the first kilowatt served; right?

MR. ELWING: I believe that's a correct assessment from a fuel standpoint. There are obviously other costs in operating a nuclear unit that may or may not make it the most or the least expensive kilowatt hour.

But most -- as far as I know, nuclear units are base loaded within the State of Florida and run around the clock.

CHAIRMAN JABER: What -- you may not be the right person to ask and I apologize for this, but it begs the question, has someone made a collective decision for the industry that the reliance on gas will be increased at the expense of not using nuclear as much? It just -- it seems like to offset the fuel cost issues associated with gas we should be relying more on nuclear.

MR. ELWING: The nuclear units that are currently in the State of Florida, as I said, based on utility plans, there are no planned retirements and those units will continue to be base loaded. So the energy output from those units, barring forced outages, should not change over the ten-year planning horizon. Because the state's energy needs are growing and there's no additional nuclear coming in or additional coal proposed to come in at this time, that growth is being made up by gas-fired generation. And so as the gas-fired generation, that energy increases, on a percentage basis it makes the numbers smaller for nuclear and coal, but the actual energy output is going to remain relatively the same.

CHAIRMAN JABER: Thank you. That was helpful. Commissioner Bradley.

COMMISSIONER BRADLEY: Define "other" for me, please. "Other."

MR. ELWING: Pardon?

COMMISSIONER BRADLEY: "Other." Which fuels would, fuels would come under the topic of, heading of "Other"?

MR. ELWING: That would be municipal solid waste, wood waste products, other forms of generation that are in the utilities' portfolios. I don't have a comprehensive list at my fingertips, but I do know that things such as municipal solid waste is included in other. Petroleum coke may be included in other. There are several coal units in the State of Florida that do burn some petroleum coke as a mix with their coal, so that may be reported as other.

We can, we can get you a comprehensive list of those other fuels, if you would like.

COMMISSIONER BRADLEY: That explanation is fine.

COMMISSIONER BAEZ: Madam Chair.

CHAIRMAN JABER: Go ahead, Commissioner Baez.

COMMISSIONER BAEZ: A question: When you've broken this out, for instance, the percentage represented by gas on these graphs, that includes PPAs, you know, that includes contracts or the possibility of contracts, and how do you compare that to, to the NUG? I mean, what, what is the difference? Is there a difference?

MR. ELWING: The fuel that is represented being burned here is based on the physical units that utilities own and that their modeling indicates they are going to be burning over the ten-year horizon. All of that is aggregated together to create the FRCC plan as we're presenting it here.

Obviously some utilities do rely on PPAs to meet their load. If that source of power is coming from a Florida unit, the utility that is hosting that unit, we are assuming they are modeling that transaction and so that fuel is being accounted for.

Energy that is being sourced outside the State of Florida I do not believe is reflected in these numbers because it's coming from various fuel sources.

COMMISSIONER BAEZ: So when you, when you represent an estimate of 48 percent coming from gas as a fuel, inside -- within that 48 percent or within that amount represented is, it is blind to what the, what the corporate source is; is that fair?

MR. ELWING: Yes.

COMMISSIONER BAEZ: Okay.

MR. ELWING: That is based on the installed capacity reported by the utilities within the State of Florida or Peninsular Florida.

COMMISSIONER BAEZ: Thank you.

COMMISSIONER DEASON: Well, maybe I can ask the question a little more directly. In the 48 percent gas projected for the 2012 time period, is any of that projected to be, to come from nonutility sources, nonexisting utility sources; i.e., from merchant plants or things of that nature?

MR. ELWING: The units that are under firm contract with the utility, it is my understanding that that fuel is included in these numbers. There are some units out there that do not have any firm contracts or arrangements with utilities, and so the fuel burned by those units would not be included in these numbers at this time.

Our next slide is dispatchable DSM or demand-side management, which is load management and interruptible load. The -- I guess it would be the magenta color on the bottom is the interruptible load over the ten-year planning horizon, and load management is shown as the light blue or cyan color across the top. Relatively unchanged over the planning horizon. We do see just a slight decrease by 2012.

This next slide is the planned reserve margin by the utilities within the State of Florida. This is the cumulative or aggregate, if you will. As you are aware, the FRCC has a 15 percent target that we have and the Commission up to this point has found that acceptable. And so as you can see for both summer and winter, we're well above that. Summer remains at or above 20 percent for all years except 2011, where it dips just slightly below 20 percent, and all winter years are in excess of 20 percent.

MR. HAFF: I have a question, Paul.

MR. ELWING: Yes.

MR. HAFF: Are there any unspecified purchases included in this reserve margin?

MR. ELWING: I'm not sure, Michael.

MR. HAFF: Okay.

MS. CAMPBELL: This is Linda Campbell with the FRCC.

Michael, I don't recall exactly if there are or not. But last year, you remember, we agreed with certain definitions or terms that the utilities would include those numbers in their ten-year site plan. So if they have stuck with that, they would be included as per the agreement that we made last year. But I have not looked at that number specifically to tell you how much of that might be unspecified purchases.

MR. HAFF: Okay.

CHAIRMAN JABER: Can you get that information to our staff before we discuss it at internal affairs?

MS. CAMPBELL: Yes, ma'am.

CHAIRMAN JABER: Because I think the reason, and I don't want to put words in your mouth, Mr. Haff, but as I recall, we specifically asked that question a couple of years ago and you've started including that number in the report that we send over.

MR. HAFF: That's correct.

MS. CAMPBELL: Yes, ma'am.

CHAIRMAN JABER: Thank you.

MR. ELWING: Okay. The reliability assessment that was performed based on the individual utility's ten-year site plans being aggregated together, the assessment focused on reserve margin review, analysis of availability and forced outage rate on the units, load forecast evaluation and a review of natural gas pipeline adequacy.

In regards to the reserve margin review, our review was to ensure that the Regional Planning Reserve Margin meets the 15 percent FRCC standard. And as we illustrated a couple of slides back, that appears to be well in excess of the 15 percent.

Analysis of forced outage rate and availability. There was a comparison done on the trends of forced outage rates between utilities' 2000, 2001 and 2002 planning studies. And we also compared the trends in availability of their units for the same planning studies, 2000, 2001 and 2002 planning studies.

This next graphic here is that comparison of the forced outage rates. This was done on a megawatt-weighted basis to try and put everything on an even measure. And as we can see from the results, the 2002 planning studies, which were the most recent planning studies done by the utilities, is showing numbers in the 3.6 to 3.5 percent forced outage rate remaining consistent throughout the year. And when you compare that with the previous year's planning studies, those numbers are remaining relatively consistent. So we're not seeing any great change in forced outage rates, which leads us to believe the units will continue to remain reliable from that aspect.

COMMISSIONER BAEZ: Mr. Elwing.

MR. ELWING: Yes.

COMMISSIONER BAEZ: Can we -- I just want to clarify for the benefit, for my benefit and probably the rest of us, in this type of graph, the lower the number, the better; right?

MR. ELWING: That is correct. Yes.

COMMISSIONER BAEZ: So if you see something going down, it's a good sign.

MR. ELWING: Yes. The percentage of -- forced outage rate percentage, as you said, the lower the number, the better it is. That's a measure of percent time, if you will, that a unit would be unavailable due to equipment failure or breakage.

COMMISSIONER DEASON: I have a question. On our other graph it was indicated that there are no significant retirements over this planning horizon, so one could conclude that the average age of the generating infrastructure is going to be getting higher. But then on the other hand, you're adding a great deal of capacity to meet growth and that may offset that so that you have a growing amount of new generation.

Do you have any idea as to what the average age of installed capacity is going to be over the planning horizon?

MR. ELWING: No, I do not. We have not done that. That is something we can --

COMMISSIONER DEASON: The reason I ask is because the trends on the forced outage rate are favorable. They're trending downward, which is a good thing. And I was just curious as to whether that is in spite of the fact that the fleet may be aging or the fact that we're adding enough new capacity that the average installed, average age of installed capacity is remaining stable or maybe even getting younger. I would just be -- if that's the information that's readily available, I think it would be helpful. I think staff probably would be interested in that as well.

MR. ELWING: Right. There are a number of repowerings that are taking place within the state, existing units that are being repowered into combined-cycle configurations. So when that is done, that does improve the reliability of those units as equipment is being refurbished.

Informal conversations with utilities in the Reliability Working Group meetings indicate utilities are committed to maintaining their fleets and doing proper maintenance. And so, yes, even though the age of the fleet may be increasing on the existing installed capacity, it's our belief that the utilities are spending proper dollars or adequate dollars, I should say, to maintain reliability. New units coming into the overall fleet for the state, yes, is going to help push down that forced outage rate by virtue of being newer machines.

COMMISSIONER DEASON: I would assume that everything else being equal, that the -- on average the older the generating fleet, the more likely there are going to be forced outages.

MR. ELWING: All things being equal, yes.

COMMISSIONER BAEZ: Madam Chair, a question.

CHAIRMAN JABER: Go right ahead, Commissioner Baez.

COMMISSIONER BAEZ: As a follow-up to what Commissioner Deason had asked you, Mr. Elwing. And I noticed that in these -- I guess in the out years, I guess starting with after 2010, you see a slight uptake in what the projections are. And understanding well that the farther out the projection gets, the less reliable it is certainly, but when you do have a trending projection or a projection trending upward somehow, how does it affect -- does it create a question about whether, or an issue whether tempering these trends with new additions as opposed to retirements is -- does that, does that raise that question when you see something trending up? I mean, I know you discussed with Commissioner Deason about that, that tension of, of keeping, keeping the FOR percentage down, whether it's by additions of new capacity and to what extent those have a compensating effect for an aging fleet. Does that equation come into question or how much you're adding in new addition to compensate for an aging fleet rather than just retiring parts of the aging fleet in greater percentages?

MR. ELWING: Had we seen a significant increase in forced outage rate or, or a definite upward trend, I would say we would certainly dig deeper and question further. Seeing a variation of only a tenth of a percent in some of these years, that does not cause us to pause or give any concern. From our viewpoint, we feel that that is a relatively stable trend. Again, obviously, the more capacity that's added, the more it's going to try and, or the more that's going to drive down the forced outage rate or compensate for an aging fleet. But, again, we didn't see anything in here that gave us alarm.

COMMISSIONER BAEZ: No. And I realize that certainly what I'm talking about is taking place almost ten years out, so there's certainly time and this gets reevaluated on a, on a regular basis.

But I guess just to confirm that the question of how much new capacity to add in relation to how much capacity is being retired, that's in constant flux based on these projections.

MR. ELWING: Well, the amount of -- yes. The amount of capacity that is added is a function of the reserve margin requirements of each of the individual utilities.

COMMISSIONER BAEZ: Well, I'm sorry. I didn't mean to interrupt. But I guess there's, there's two types of capacity addition. When you're dealing with out-projections, you're either dealing, you're either adding capacity to deal with growth or you're adding capacity to deal with -- well, maybe adding is not proper, but you're replacing capacity with new, so.

MR. ELWING: Yes, sir. Right. I was going to follow-up by saying, the utility doing prudent planning would be looking at the age of their fleet, the reliability of their fleet, and there does come that point of diminishing return where you do make that decision to retire capacity simply because of its age and its efficiency, its reliability. You retire it in favor of new capacity.

MS. CAMPBELL: If I might just add, looking at our load and resource plan, our install capacity in 2003 is around 40,354. 2012, we're looking at 54,780. So that's roughly 14,000 that we're going up in installed capacity. And I think in a previous slide Paul showed that we had around 16,000 was projected additions. So there's probably not a whole lot of retirements going on. A lot of that new capacity is taking care of the additional growth.

COMMISSIONER BAEZ: Right. Thank you.

MR. ELWING: Okay. Our next slide continues on with the reliability assessment. And we also looked at availability of units, and again we did that on a megawatt-weighted basis to get a level measure or level playing field from which to measure.

And again we're seeing the availability following similar trends as what we had seen in the past two years. Availability values for 2002 are in the low 90 percent. We do see a slight drop-off there in the 2011 and 2012. But, again, nothing there gave us any concern.

MR. HAFF: Mr. Elwing, I have a question. It may just be the scale you're using on the vertical axis of the graph, but it looks like there's a sudden jump between 2004 and 2005. And could you explain that, along with on the prior slide the forced outage rate seems to be at its highest in that same exact year. Is there any one factor or number of factors that you can point to that might have caused that?

MR. ELWING: Not in particular. The jump in availability, I'm going out on a limb a little bit here, but I believe that is due to new units coming on-line in that time frame, and so we see the increase in availability.

I realize forced outage rate goes up a tenth of a percent in that same year. I don't really believe there is any correlation there.

MR. HAFF: I'll follow up with you later.

CHAIRMAN JABER: Go ahead.

MR. ELWING: Okay. The FRCC Reliability Assessment also included a review of natural gas pipeline adequacy. And some of the things that were looked at there is formation of an FRCC Gas/Electricity Interdependency Task Force to review the relationship between the gas pipeline and electric system operation system and planning. Ms. Campbell is going to give you a report on that in a few minutes in greater detail.

There was also a review of gas pipeline planning, operation and maintenance; review existing and future pipeline capacity; develop guidelines for maintenance coordination between utilities and the gas industry; and develop communication protocols between the FRCC Security Coordinator and the gas control centers to provide better coordination and communication between the utilities and the gas supplier or gas pipelines.

COMMISSIONER DEASON: Can you -- the next-to-the-last bullet point on the previous slide.

MR. ELWING: Yes.

COMMISSIONER DEASON: And maybe we'll get more on this later, I'm not sure, but you say develop guidelines for maintenance coordination. Is this maintenance of the pipeline or maintenance of gas-fired units or both?

MR. ELWING: I think it's primarily targeted at the pipelines so that we can understand when they're going to be doing maintenance because that would have a direct impact on the delivery of gas to the utilities. Is that correct? And also utility maintenance as well. So it is, it is both.

In summary, the planning reserve margins remain at or above 20 percent for all but one year of the ten-year forecast period.

CHAIRMAN JABER: I wanted to ask you about that. There was the previous slide; I think it was a bar graph. It was 2011 that looks like it was below the 20 percent reserve margin.

MR. ELWING: Yes, ma'am.

CHAIRMAN JABER: As Commissioner Baez said, that's obviously, you know, some time from now. And I'm assuming, while we should know about it, you don't seem to be too concerned. Is that because of the plants that are coming on-line 2005, 2006?

MR. ELWING: Yes. Because it came back up the following year, that may just be a timing issue of when utilities are bringing capacity on, that a unit may have come on in the fall rather than in the spring to meet the summer peak because it was just that single summer where it dipped slightly.

CHAIRMAN JABER: You have not -- you didn't take that into account for that year? I mean, I'm sure there's a projection -- well, I know there's a projected capacity for Martin, FP&L-Martin, the Hines units of Progress. Were those not factored in, for example, for 2011?

MR. ELWING: Yes. These numbers are based on what the utilities have provided the FRCC, and so it's based on their timing. And so the units that they have put in their ten-year site plan with those timings, that is what determined these numbers.

CHAIRMAN JABER: So with the four, I think it was four that we approved for those two large utilities, you're still projecting less than 20 percent for 2011. So what's not included in there then? What may be coming between now and 2011?

MR. ELWING: Well, as I said, I believe that it is just a timing issue. The, the number for 2011, if memory serves me, was 19.8 percent. So it's just slightly below 20 percent. And so, as I said, in order to be counted for summer capacity, we asked utilities that the units be on-line -- is it June 1st? And so if the unit came on-line, was projected to come on-line after June 1st, it would not be counted in that summer's capacity and go towards that summer's reserve margin.

CHAIRMAN JABER: Okay. Thank you.

COMMISSIONER DEASON: Let me -- you want me to go ahead or --

MR. ELWING: Yeah.

COMMISSIONER DEASON: Okay. But for -- the FRCC planning criterion though is not 20 percent; is that correct?

Isn't it 15 percent? And you're well above that.

MR. ELWING: That is correct.

COMMISSIONER DEASON: It is only for the investor-owned utilities that have volunteered to achieve a 20 percent --

MR. ELWING: That is correct.

COMMISSIONER DEASON: -- that that particular margin, that particular reserve margin applies.

MR. ELWING: That is correct. The numbers we've presented here are the aggregate for the entire Peninsular Florida, the FRCC region.

COMMISSIONER DEASON: And let me ask you a further question. And it's my assumption that with the size of all the generation in Peninsular Florida and the diversity therein that it is, it is assumed that 15 percent is adequate for all of Peninsular Florida, including all generating sources; is that correct?

MR. ELWING: That is correct.

COMMISSIONER DEASON: Okay.

CHAIRMAN JABER: Commissioner Bradley, you had a question?

COMMISSIONER BRADLEY: Yeah. Your summary says that the reserve margin remains at or above 20 percent for all but one year in the ten-year forecast period. Which, which year is that?

MR. ELWING: That was summer of 2011, and it dipped to 19.8 percent.

COMMISSIONER BRADLEY: Okay.

MR. ELWING: So just slightly below 20 percent.

COMMISSIONER BRADLEY: And why is that, even though it's a small dip?

MR. ELWING: I feel that it is a timing issue of when the capacity in that year is being projected to come on-line. There is capacity projected to come on-line in 2011. And so it may be a timing issue to where it's coming on after the summer peak reporting period and so it is not getting counted for summer peak.

COMMISSIONER BRADLEY: Okay.

CHAIRMAN JABER: Go ahead, Mr. Elwing.

MR. ELWING: And then in conclusion for the reliability assessment for the FRCC region, the results of this year's studies indicate that the Peninsular Florida electric system is reliable for the next ten years from a planning perspective.

That concludes my portion of the presentation, unless you have more questions.

CHAIRMAN JABER: Commissioners, do you have questions on this part? Okay. Thank you.

MR. ELWING: At this time Mr. Leo Green is going to come and give you a presentation on the load forecasting aspect. Thank you.

CHAIRMAN JABER: Now we're not supposed to read into this that it took three of you to replace Mr. Wiley; right?

MR. ELWING: No.

MS. CAMPBELL: No.

MR. GREEN: Good morning, Commissioners. My name is Leonardo Green. I am currently employed with Florida Power & Light as the manager of forecasting. On this occasion I'm appearing on behalf of FRCC's load forecasting task force and I'm here to address the demand-side of the equation.

The reliability plan assumes a given level of demand of electricity. Last year in the ten-year site plan there were quite a number of questions regarding demand, and we thought it convenient that we present the Commission with the work that we do in evaluating all the utilities' load forecasting efforts, and that's my presentation today.

I'm going to talk about the following points and why we did it, the review of the individual company methods, some historical insight as to why we're experiencing the growth that we have in the State of Florida, how good is the forecast, and then I'd like to leave with you some uncertainties that might exist with the forecast and how the utilities are treating these uncertainties.

The reason we did this exercise, the forecast evaluation is there -- we believe that the assessment, reliability assessment requires that the load forecast be as accurate as possible; whereas, it's impossible to predict precisely what the load is going to be, we need an unbiased load forecast. This means to say an objective as close to reality as possible.

Given that, we ask the question: Are the forecasts that the utilities are putting together, are they suitable for this exercise that's been done? And with this exercise we also hope to identify if there were any problems that might exist that could create some reliability problems for the State of Florida. And finally we are a region, one of NERC's regions, and they have some planning standards that we need to comply with, one of which is an evaluation of how good the forecast is.

In our evaluation exercise we considered the 12 largest utilities in the State of Florida, which represent approximately 98.5 percent of the load in the state. And what we looked at is what's the historical accuracy of this forecast, under the presumption that if it's historically accurate, we believe that it might be accurate also in the future. Is there any homogeneity in assumptions across the utilities? How good are the forecasting models that the utilities are using? Is the forecast itself suitable? And then there are some sanity checks that we choose to use.

What we found is that there is no bias in the forecast error. There is not a tendency to overforecast or underforecast. And I guess I should clarify that I'm speaking here of peak demand. There is no pattern -- there is almost the same probability of overforecasting as underforecasting. There is some problems that we are going to show with the winter peak, but that has to do with weather.

There is homogenous assumption across the utilities; whereas, each utility's service territory has its own particularities, we believe that the assumptions are similar enough that we could qualify them as saying that they're homogenous. And this is important because each utility uses inputs coming from different sources.

Once upon a time, only the major utilities in the State of Florida could afford to have sophisticated and elaborative forecasting technologies, but that technology has increased, has improved. And with the new computer technology it is affordable so that almost all the utilities in the State of Florida can afford to use this technology now and we're seeing the results in the forecast errors that we're getting.

We found that the forecasts are within the criteria for the sanity check. And what's important through this exercise that we're doing today is each year the utility gets the opportunity to adjust their forecast to the most recent facts, which corresponds in reality to some kind of a self-correcting process that's built into this process.

I wanted to give some historical insight before I show what the forecast is as to what has happened recently. Why are we seeing the growth in load that we, that we have in the State of Florida?

In the recent past we have had a mixed economic performance; whereas, the performance in Florida is by no means stellar compared to the 1990s, we have one of the top three economies in the union. Okay. So last year when the union was losing 3 million jobs, we created over 70,000 jobs, and that created some migration to Florida seeking jobs. So our economy, whereas, it's not as good as it used to be in the 1990s, it's doing much better than most of the rest of the state. And we have rebound from 9/11 much better than any one of the forecasts thought we would be at this point.

In the recent past we have had quite a bit of volatility in prices, we have strong customer growth, and all the utilities in the State of Florida use as a basis the projection of population that's provided by the University of Florida, the Bureau of Economic and Business Research, University of Florida. And what we have seen is that we're getting strong customer growth recently. And surprisingly it's not the retiree that is creating that strong customer growth, but people within that working age 25 to 50 years, people that are coming to invest. So it's a different type -- it's almost like a shift in the demographics, but it has resulted in strong customer growth. We have an active housing market because of the low mortgage rates, and this has led to the high growth in, in peaks.

How good has the forecast been? How good is the forecast that the FRCC has put together? As I said previously, if we consistently over or underforecast, that's not a good thing. Furthermore, if that variance between actual and forecast increases over time, that is not a good thing. However, over the last five years we have not found a trend of over or underforecasting and, furthermore, the difference between actual and forecast has been decreasing to say that the forecast that FRCC has been providing for this reliability assessment has been improving in accuracy.

I'll give you an example of how this works. I'm sorry for those of you that can't make out these numbers, but I'll explain what's going on here.

The second column is the actual customers, actual summer peak. The following columns are the ten-year site plans that have been provided by FRCC ever since 1995. So on the bottom is the forecast error that is -- I'm comparing for each year the forecast with actual. The actual is the second column where it says, "Actual Summer Peak." To the bottom is the forecast error.

We can see in the bottom that we have some positives and we have some negatives, meaning to say that there is a tendency to fluctuate, not necessarily over or under. But what's surprising, and as you move to the right, that is as we come closer to present time, the forecast error is becoming smaller and smaller. And I'd like to mention in 19 -- in 2002 the difference between actual and forecast was .3 percent. I'd like to remind you that we have a reserve margin of 20 percent, which in addition for other things it is intended to cover some of the forecast error that might exist, granted -- just one second -- it could happen that we experience an extremely hot summer, which would throw these numbers off some. However, if we look at that one line, like starting in 1998, the top line to the bottom going down diagonally, we started out with about 4.9 percent error, 4.3, 1.9, .9, .5, .3 percent; extremely accurate forecast. So we feel very confident with respect to the summer peak.

With respect to the winter peak it's a different story. We see a predominance of negative values, meaning to say that the utilities have been overforecasting. However, the reason for this has been that in the last ten years I think we have only had two winters, and it seems like the cold fronts that are coming down reach the middle of the state and they don't progress. So this is there primarily due to the fact that we have not had cold winters; however, the utilities think that they should plan for the occurrence whether we have it or not and that's the reason why these numbers have a predominance of a negative value.

I'm going to speak some about the forecast findings, and now we're going to look at the outlook instead of history and I'm going to compare the 2003 and the 2002 forecast.

It's not very clear, but historically, as Paul said -- let me back up a second. As Paul said, this forecast is slightly higher than the forecast we presented last year. And in the box to the bottom left it shows that last year on the average historically we were growing at the rate of 1,164 megawatts per year. And the forecast last year suggested that we would grow at the rate of 1,024. This year we're raising that and suggesting that this forecast is meant to grow on the average at 1,107 megawatts. Very similar.

I'd like to call your attention also to the last column that's percent and it's -- the only intention here is to show that that's misleading. 1,164 megawatts represented 3.4 percent, where almost a similar amount represents only 2.3, 2.5 percent. So what happens is as the base gets bigger, the growth looks smaller, but what's important is the absolute number.

Similarly with the winter peak, we are growing slightly better than last year, better than the plan for last year. In the bottom left the historical growth has been 1,847, but that number is misleading. I'm using actual numbers here. I'm not using weather normalized numbers. And in 2003, that's this year, the winter of this year was extremely cold. We had a winter peak. And in the starting year, which I think was 1993, we did not have a winter peak. So the two extremes are misleading. So the growth rate that's shown here is somewhat misleading. What's important is that the forecast is substantial, is slightly higher than last year.

As I said, that's our best outlook. However, there's certain things that are beyond our control, and I've listed four of them here that I'd like to deal with very briefly.

The first one would be customers. Customers in the State of Florida is the primary driver of the growth in peak demand. There are demographic changes, as I mentioned, in the State of Florida. People are coming to Florida not necessarily to retire anymore. People are coming to Florida because Florida creates jobs. It would be surprising if I mentioned that on the west coast of Florida the second state in the United States that's sending us immigrants or new customers is the State of California. And there are several reasons for that: We have favorable taxes, tax laws; people are bringing their business to Florida because of the economy that we have; we are privileged by our geography, with this new globalization it seems like we're almost the center of the north, south, east, west quadrant. And so we are very attractive to business.

There's a tremendous amount of flight capital coming from South America and these are capital that are coming to invest in companies that they're opening in Florida.

And the same thing as the relocation of national and international companies. A lot of companies have been relocating to Florida from the rest of the United States.

It is estimated that approximately each day 1,000 veterans from the Second World War are dying and that wealth that they have accumulated, they're leaving it to their heirs, and it would seem like the preference of the heirs is to buy a second home or even advance retirement plans to the State of Florida. And that is one of the primary reasons why we're getting that growth in the last few years in customers.

We're running out of land to build new homes; however, almost all the major counties have what's called a community redevelopment association in place and the growth is going back into the urban centers. The predominance of large condominiums in the downtown depressed areas is being seen in many parts of the service territories of the different utilities. However, there are some negatives there that's the reason why we're not flooded by more people, and that is we have a problem with transportation and we have a problem with the ability of the local government to service the population that are coming. This population that we're getting demands a lot of services, schools, hospitals, things like that, and it's creating some problems. So that is putting some of the brakes on the migration into Florida. But we believe that what we're experiencing is perhaps the first wave of retirees of the baby boomers.

The weather is only a short-run impact. One year to the other the weather could create quite a divergence between actual and forecast. We do not necessarily believe that it's becoming hotter or significantly hotter than in the past. What we have observed is that the growth of our customers is occurring in the regions that are less mild, if there's a word like that.

For example, the coast areas are filled up. Those are the coolest areas. Migration is inward, which is hotter, and migration is moving north, which is hotter and which is colder, which is creating a demand for more electricity.

How do we handle that? Each utility that we reviewed has its own definition of normal weather, and it's a definition that best fits the service territory that they have. We all depend on data that's coming from NOAA, the National Oceanographic and Atmospheric Administration. But the number of years that we use as an average to define that normal depends on the service territory. Some utilities are using a rolling 20 years, some utilities use a rolling 30 years and some even more than that, and that's their definition of normal weather. And so we do not try to forecast what weather is going to be, but we assume normal weather into the future, with those caveats that the growth is occurring in more adverse situations.

The economy, as I said, is doing good. I would not say stellar, but it's doing good. The State of Florida grew by 2.6 percent last year. And as I mentioned before, the nation was losing jobs and we were creating jobs. And the economy has rebounded much better than what we thought it would do after 9/11. Tourism is not at the level that it was before 9/11, but it's coming along nicely. And because of the fear of some people to fly overseas, we're capturing some of that, some of that tourism. And some of the occupancy rates of the hotels are edging up very closely to what it was before 9/11.

What was -- what was pleasing at the time we did the evaluation is that each one of the utilities was using a different forecasting outfit to give them an outlook as to what the economy is going to be.

For example, Florida Power & Light was using Global Inset (phonetic), which used to be DRI. TECO might be using Economy.com. FPC might be using the University of Florida. So we had a mixture of economic outlooks. It seems like the forecast then would be an average of all, of several forecasts of what the economy would be like. And that basically is a Delphi approach, which is an average which is spreading the risk across the state, meaning to say that we are not depending on one outlook. And if they happen to be incorrect, then the whole state would be incorrect. We believe that we're covering that uncertainty like that.

And, finally, based on the findings of that evaluation that was performed, we believe that the forecast is suitable for the reliability assessment that we're presenting here today. It captures the trends, and whatever new initiatives might be out there has been presented. The short-term deviations that we see in those forecast areas or forecast variances are due to extreme weather occurrences and unusual economic conditions that are short-term but that revert to some kind of a mean eventually, and that the forecasts are self-correcting and they incorporate the very latest information. Based on this the Load Forecasting Task Force believes, Commission, that the forecast used in this exercise is suitable for reliability assessments. If there are any questions, I'll gladly try to answer them.

CHAIRMAN JABER: Thank you, Mr. Green. Commissioner Deason and other Commissioners, if you have questions.

COMMISSIONER DEASON: Thank you. I have a question on Page 12 of your presentation. This is the winter peak forecast evaluation.

MR. GREEN: Yes. Yes, sir.

COMMISSIONER DEASON: And I believe in the lower left-hand corner of the page there's a box, and I think you explained that for the historical growth for the '93 to 2002 period, that that, there was a little bit of an aberration there because of the effect of a lack of winter temperatures in '93 and apparently there was some fairly extreme temperatures in 2002; is that correct?

MR. GREEN: 2003. That's correct.

COMMISSIONER DEASON: Yeah. Okay. So we have a really high historical growth rate, but that is probably not really indicative.

But what I want to concentrate -- my question really applies to the forecast for 2002 and the forecast for 2003, realizing these are forecasted numbers, but there seems to be a fairly significant decline in the forecast from 2002 to 2003, both in absolute terms of megawatts as well as a percentage basis. Could you, could you -- perhaps you explained that and I just missed it, but if you could amplify on that, I'd appreciate it.

MR. GREEN: Yes. The history, starting with the history, the 2003 value -- and that's a mistake. That should say 1993 to 2003. Sorry about that. That includes the 2003 extreme winter conditions that we saw this year. So that gave a high history. However, the forecast, the starting value is also what we had in 2003, which was abnormally high. And because the starting value is so high, it makes the forecast look as though it's small. However, if you look at the graph and compare both plans, this year's plan is higher than last year's plan, similar growth and starting from a higher value. It's just that that one year, 2003, is given distorted values.

COMMISSIONER DEASON: I understand. Thank you very much for the explanation. That explains it.

CHAIRMAN JABER: Staff, did you have any questions of Mr. Green?

MR. HAFF: No.

CHAIRMAN JABER: Thank you, sir.

MR. GREEN: Thank you.

CHAIRMAN JABER: Next presentation.

MS. CAMPBELL: Good morning, Commissioners. My name is Linda Campbell. I'm the director of reliability for the Florida Reliability Coordinating Council. And I wanted to talk to you all this morning and share with you the work that is going on with the new task force that's been created, the FRCC Gas/Electricity Interdependency Task Force.

This task force was established this January, this past January by the FRCC board of directors. The task force composition includes gas pipeline owners. We have representatives from both Gulfstream and Florida Gas Transmission, we've got electric system operators, generator owners, the local gas distribution companies, there's a representative from People's Gas there. The Florida Public Service Commission staff is participating as well as a FERC staff member, and both of the Commission -- both the Florida

Public Service Commission and FERC staff are there as observers.

The reason the board created this is evidenced in the next slide, and you've seen this throughout the reports of both Mr. Green and Mr. Elwing. And we have an increase in natural gas use occurring in our region. This slide will show some actual numbers starting in 1998 and we've got our forecasted numbers ending in 2012, which is part of our ten-year load and resource plan this year. And this is being represented as the percent of annual net energy for load. So this is an energy value, not a capacity value. And as you can see, the dependency is increasing. We were at just slightly over 15 percent in 1998 and were projected to go up to about 48, almost 50 percent in 2012. And so with this dependence increasing over the years, our board of directors felt it was very prudent to take a look in very detail about the relationship between the gas pipeline operation and the, the reliability of our bulk electric system.

CHAIRMAN JABER: Ms. Campbell, for what purpose? To determine whether the pipeline capacity is sufficient? Or help me understand. I think the task force is a great idea. I just need to get a better grip on the purpose for which it was intended.

MS. CAMPBELL: Well, if I could --

CHAIRMAN JABER: It's in here?

MS. CAMPBELL: I'll answer that in the next slide.

CHAIRMAN JABER: Okay.

MS. CAMPBELL: We'll get a start on that. And then if you have any further questions, I'd be happy to answer them.

Some ground rules that the task force came up with, the first part we want to say what it's not. The task force was not created to review gas supplies. Also, it's not looking out to indict the gas pipeline practices. The gas pipelines are operating per their tariffs and we don't have any problems with that, so it's not trying to figure out a bad guy.

We're not looking for an indictment of the electric generation practices and we're not planning to review gas markets or gas prices. And a detailed study of gas pipeline flows is also not anticipated as a part of this work.

What we are hoping to do is review the interdependency relationship between the gas pipeline operations and planning and the electric generation operations and planning focusing on the reliability impacts to the bulk electric system. So we want to look and see where they cross, how do they operate both individually, and how do these things impact the reliability of the system and where may we need to look further.

CHAIRMAN JABER: Does the review or your dialogue among the task force include any involvement by the FRCC and the new, the proposed Bahamas pipeline?

MS. CAMPBELL: We will probably be looking at those alternatives. We had a representative, and I can't remember the company, of a storage facility that came and gave information in a presentation. So all of those kinds of things will be part of discussions in the learning that this task force will be going through.

CHAIRMAN JABER: And this next question is really going to show my naivete with regard to the FRCC, and I apologize for that in advance. But do you contemplate taking an activist role in advocating for another pipeline into this state? I mean, where might you stand in the whole Bahamas pipeline debate: As an observer, as a reviewer, as an active participant?

MS. CAMPBELL: I guess what I think that we would probably do, we'd be more in the learning and trying to identify possible solutions or problems. And if there are risks out there with dependence on one pipeline or other, that we would try to identify what solutions or possible mitigations may occur. I don't think we would advocate any one position. But really this task force is looking to identify what's out there and where we may need to go further to decrease any risk that we might identify.

CHAIRMAN JABER: Okay. That's helpful. And where would your concerns be raised? Here at local levels? Where would you --

MS. CAMPBELL: Well, certainly at the task force we will have all of the participants being there. And then I think later on I'll show what we're hoping to do by involving the Public Service Commission, they'll be involved, FERC will be involved, and we may discover that we need to try and, and raise the level of understanding other avenues and bring these risks and implications out to other folks.

At the same time that FRCC is undertaking this effort there is a parallel task force going on at the North American Electric Reliability Council, NERC. They've also got an interdependency task force that is doing this similar kind of thing, but looking after the whole country or the North American continent. And Ken Wiley is participating in that effort as well because we don't want to duplicate efforts. And what we may learn that they're doing at the NERC level we can either help or put into practice here. We'll hope to take advantage of that.

CHAIRMAN JABER: Thank you.

MS. CAMPBELL: Some of the preliminary goals that have been identified -- and these have not really been fleshed out completely yet. The task force has just met once face-to-face. These goals were identified, but really they'll be discussed further at the next meeting. So these are just some things that were put out on paper and identified as some real preliminary goals that we have.

And one of the first ones would be to develop guidelines for a communication protocol between the security coordinator for FRCC and the gas control centers. And this is really something that we hope to get into place and we've started some work towards this already by visiting the gas control centers. We've gotten the input on our emergency contact list, we're on theirs, a lot of that. And we want to do that mainly for emergencies. We don't want to burden anybody, either our security coordinator or the gas control centers, with everyday stuff. We really want to have a communications system in place so if emergencies arise on the pipeline that we need to know about that we can react to, that we've got that going. It would not displace communication that's between the gas control centers and the shippers that is there today. There's a lot of communication that takes place every day between those entities and we do not want to displace any of that or take the place of it.

And what we may wind up finding that would be helpful would be a contingency list of the types of events that would trigger these kinds of communication. So perhaps the gas pipeline might not know an emergency condition that we feel would be an emergency, but if it happened on their system, we'd say, hey, this is the kind of thing we want you to tell us about because this will have impact on our reserve margin or just whatever. So we hope to perhaps identify those kinds of events that would help that communication go forward.

Another preliminary goal we have is to conduct a regional analysis of the gas pipeline capacity. Here we would be looking at the maximum pipeline delivery capability trying to answer the question: Do we have enough pipeline capacity for all the generators that are either now in existence or being proposed over the next ten years or in the future?

We want to look at the total connected capacity, the firm transportation for that capacity, what's the maximum transportation capacity needed to operate all of the capacity at maximum output? Another way of saying that is, you know, we need -- there's, there's firm capacity out there right now, there's interruptible capacity out there. Is there enough that if we need to have all generators on-line at the same time for something, and, again, I'm talking about the ones that are using natural gas, would they be able to operate? So we need to look at those kinds of things. We really want to look at this in detail for the next five years.

And then one of the things we've talked about is a connectivity diagram, and this might be analogous to a load flow diagram that we have for the electric system, so that we could sort of see in a picture format where all of the problem areas might be. Is there a lot of concentration of units in a certain geographic location and how is the pipeline capability to that location? And so hoping that that diagram might be of use for us in just sort of getting a high level overview looking at it.

Another preliminary goal would be to establish the monitoring system that would report all gas events which threaten or cause electrical reliability problems. We've already taken some steps this past year where we have included in, in our declaration of a generating capacity advisory or a generating capacity alert if there were problems on a gas pipeline. We have added that into the conditions that might trigger one of those events, and so then it would get us into our normal capacity emergency process. And so we've started some of that. But what we're really looking after is trying to get plenty of lead time so that if something does occur on a pipeline that might threaten our reliability of the bulk grid in the FRCC region, we want to have time to deal with it. So that's what we're hoping to do there.

We want to monitor and perhaps, if necessary, participate in FERC activities on operational matters that -- for things that would affect reliability. We're not quite sure what that might be or how that might happen. But, you know, when the pipelines go for getting tariffs approved or other things, we need to be on the lookout to see if there might be any part of those that would negatively impact the reliability of the grid. So that's just something that, you know, we've got as a possibility that we may need to get involved in some of those things. And, again, we'd be focusing strictly on the reliability implications, not any of the commercial or economic type of implications that the pipeline companies may have.

And then another preliminary goal would be to review the gas pipeline curtailment policies and see what kind of impact they may have on electric system reliability.

One of the things that comes to mind, you know, is the curtailment order. If they do have a problem on the pipeline and experience diminished supplies or ability to get the supplies to their customers, what kind of order do they have in their curtailment practices? Should there be a different order perhaps that would prioritize the delivery to the electric generator so that that's not lost? So that would be another area that we need to look at to see if there could be any risk and what possible mitigation there might be to make that better.

I guess lastly since this group is very new, what we're hoping in the anticipated deliverables is really that we see this as a first step. And what we're really hoping to do is produce a record of what these identified risks to the electric system reliability might be because we've got a lot of things in mind that we think might be out there but we're really not sure. So as we discover, we want to document that and get it down and then hopefully develop potential solutions to mitigate these risks. We don't know -- we may have some that are real easy that we can do and they're like a no-brainer. There may be others that are going to require further investigation that we don't know exactly how to go and accomplish making that better. It may require changes from the Florida Public Service Commission or even at FERC, the treatment in, you know, the way that generating entities are viewed in looking at the diversity equation. So we just -- we don't know where that will lead. And then it may require new and different business practices and plans to implement.

Right now, as I mentioned earlier, the pipelines are operating according to their tariffs. We haven't seen any problems or abuse or anything of that nature at all. But maybe going forward we all may learn that we need to think differently when we get to a 50 percent dependence on gas.

And so these are what we're kind of hoping to do. We've just got started. I guess what I'd like to offer, if this is of interest to you, that we know you have regular internal affairs meetings. If you would like, we would be more than happy to come to an internal affairs meeting toward the end of the year and give you an update and a status report on where the task force is and keep you abreast of what's taking place here.

CHAIRMAN JABER: Staff, who's our staff observer on this?

MR. HAFF: I believe it's Mr. Jenkins.

CHAIRMAN JABER: Okay. Joe, it's you? Okay.

I think, Commissioners, I'm very interested in this. I think it's a great idea. I think the more we rely on natural gas as a source, we should certainly be dialoguing and communicating with the pipeline companies to -- if nothing more but to coordinate. But I don't -- I personally don't need a presentation at the end of the year, if we just rely on our staff to keep us posted.

MS. CAMPBELL: Okay.

CHAIRMAN JABER: And that would be a request I have of staff: Just keep us posted. Don't blindside us with any concerns that may be raised. And I think you could also take the internal affairs in November, December when you present the ten-year site plan report as an opportunity to bring us up to speed on the meetings you all are having.

MR. HAFF: Yes.

CHAIRMAN JABER: Commissioner Baez, do you have a follow-up?

COMMISSIONER BAEZ: Ms. Campbell, a question on the last slide, the development of potential solutions. Is it, is it your understanding, and I know y'all have only met once, but certainly would it be the task force's understanding that potential solutions also includes -- does it include an analysis of whether 50 percent gas reliance is even appropriate?

MS. CAMPBELL: I'm not sure that we're going to look at it from that perspective.

COMMISSIONER BAEZ: Okay.

MS. CAMPBELL: Because we're really concerned with just the reliability impacts.

COMMISSIONER BAEZ: So you're taking, you're taking this 48 percent and saying --

MS. CAMPBELL: This is what we have.

COMMISSIONER BAEZ: -- this is a given. Right.

MS. CAMPBELL: Let's figure out if it works or not and how to make it work. Because the choice of the type of generation is the individual utilities that are members.

COMMISSIONER BAEZ: Obviously, yes.

MS. CAMPBELL: So we're just going to look and see what we have and can we make it work reliably.

COMMISSIONER BAEZ: Okay.

CHAIRMAN JABER: One of the things that I've really taken away from the companies in their efforts to mitigate the impact from natural gas prices on the consumer is the necessity for fuel diversity in this state. And I think that our companies have done an admirable job trying to ensure diversity, but they recognize that that's a major part of the answer to mitigating the cost impact.

And my question to the FRCC is have you thought about establishing a task force or do you currently look at the issue of what might be the appropriate fuel diversity for the state long-term?

MS. CAMPBELL: I guess we have not looked at this point in time to the appropriateness of the fuel diversity. We're looking, of course, at what it is. And as we've seen this dependence it's raised flags. And so we're trying to look at that to see from a reliability perspective what is there looming out there in terms of potential risks and then potential solutions. And I guess one of the things is we identify these -- if we see that there's something that's going to be very difficult to overcome, then we would probably, through the efforts of the membership, including the Commission staff and FERC staff, we'd raise that to the attention of folks so that we could figure out what's the right thing to do.

CHAIRMAN JABER: Okay. And my final question: With regard to who you have participating in this task force, do you have all the state agencies you need?

MS. CAMPBELL: At this time I think that we do.

CHAIRMAN JABER: Does DEP have a role in any of the pipeline issues?

MS. CAMPBELL: I guess potentially they could, but at this point they haven't participated. The membership is open to FRCC members and observers. You know, some of these are not members. And so if there are folks that are interested, we are certainly interested in their contacting us to participate as appropriately.

CHAIRMAN JABER: The only reason it sort of flew out at me is with the merger or combination of the Department of Community Affairs and DEP in regard to the Energy Office that used to be housed in the Department of Community Affairs, it seems like they are playing more of an active role in assessing some aspect of the energy needs of this state. I wonder if it's wise to get them involved on the front end rather than later on in the process.

I don't know if they even know about this. Do you? Have you all reached out to them?

MS. CAMPBELL: I don't know. I don't know.

CHAIRMAN JABER: Is that -- do you mind taking that question, it's just a question, back to Mr. Wiley and have you all think about that a little bit more?

MS. CAMPBELL: Sure. Be glad to.

CHAIRMAN JABER: Commissioners, do you have any questions of Ms. Campbell? Staff?

MR. HAFF: No, ma'am.

CHAIRMAN JABER: Thank you, Ms. Campbell. Does that complete the presentation from FRCC?

MS. CAMPBELL: Yes, it does.

CHAIRMAN JABER: Thank you. What I'd like to do, Commissioners, is give an opportunity to the rest of the participants to get their handouts to us. And while they're doing that, let's take a ten-minute break and come back and finish the next two groups of presentations. So if you have a handout, this is a good opportunity to get it up here. Thank you.

(Recess taken.)

CHAIRMAN JABER: Okay. Let's get back on the record.

Commissioners, just for purposes of allowing you to organize your handouts, the utility presentations will be in the following order: Progress, FPL, Gulf and TECO. And you should have handouts from each of those companies: Progress, FPL, Gulf and TECO.

For the next round it's going to be FMPA, GRU, JEA, Lakeland, OUC, Tallahassee and Seminole. And if I'm not mistaken, we don't have a handout from Lakeland, which is okay. But just for the purposes of the Commissioners, you probably won't find a handout from Lakeland.

Okay. Mr. Haff.

MR. HAFF: Okay. First on the utility presentations will be Progress Energy. And let me remind everyone to say their name so the court reporter can get your name when you're giving your presentation. We'd appreciate it.

MR. CRISP: Good morning, Commissioners and staff. My name is Ben Crisp. I am director of resource planning for Progress Energy. And it's a pleasure to be here this morning and give you our ten-year site plan overview presentation.

In addition, at the end of our ten-year site plan presentation we will give you a very brief overview of some studies that are going on currently. They are about our impact of gas prices on new coal development. So once we finish the questions on the ten-year site plan, I'll step in and give kind of a quick overview of that presentation as well.

Reliability criteria for planning purposes has not changed this year for us. We're still planning to the 20 percent minimum reserve margin. Loss of load probability is less than one day in ten years. We will meet the 20 percent reserve margin criterion with the implementation of the Hines 2 addition this winter. Hines 2 will come on-line in December of 2003, and the 20 percent margin will be maintained thereafter.

This graph depicts the demand forecast for Progress Energy Florida. The solid lines are the actual winter demand served and the winter total demand looking forward. The dotted lines or hashed lines are the actual summer demand served and the ten-year site plan summer total demand going forward.

As you can see from the trends on the winter lines, the trends match up. On the summer lines you see that the actual or historical, there is a drop-off from 2002 to 2003, and that is because of some wholesale contract load that is expiring in 2002. So you would expect about a 500-megawatt disconnect there. It will -- the load will go down in 2003.

When we submitted our ten-year site plan in April, we submitted it with the addition of three peakers. As you can see in your presentation, in 2003/2004 we will bring Hines 2 on. And that's the April 2003 plan column that I'm talking about right now.

In 2004 and 2005 we were going to bring on a peaker. It was planned on being a GE7FA peaker. In 2005/2006 we were planning on bringing on Hines 3, and that's still going according to plan. 2006 and 2007, we're planning on bringing on two more peakers identical to peaker number 1. In 2007 and 8 we're planning on bringing on Hines 4.

We have since revised our plan since we were able to take advantage of an opportunity purchase that provides economic benefits to the ratepayer as well as it gives us more planning flexibility for the addition of those peakers out in time. So under the revised plan column you see Hines 2 coming on-line once again in December of 2003. You see a winter purchase in 2004 and 2005. Hines 3 comes on-line in 2005. And then the three peakers will be built and added into the mix in 2006 and 7, and Hines 4 coming on-line in 2007/2008.

Like I said, the addition of that opportunity purchase for the year 2004 and 2005 provided some, some significant financial benefits for the ratepayer. That's why we chose to move forward in that direction.

The bar graphs show the additions of the generating units. The yellow bars in 2003/2004 and 2005/2006 are the Hines 2 and Hines 3 units. You see that the three bars from 07/08, 09/10 and 11/12 are slightly lower. That's because they're generic capacity combined-cycles and they have not been spec'd out yet for total capacity output. Hines 2 and Hines 3 are rated at 582 nominal megawatts of generation.

The peakers that were added -- this is what was submitted within the ten-year site plan. The one peaker at approximately 180 megawatts winter capacity and two more peakers in the '06 time frame, for a total of 360 megawatts of capacity.

And here's what we've revised the ten-year site plan to reflect. You see the blue box in 04/05. And what's happening there is we're going to make the winter purchase there in lieu of that peaker, and we shift the peaker out to the 06/07 time frame. No effect on the combined-cycle additions.

One of the other benefits for making that winter purchase is that it enabled us to smooth out our reserve margins and make a little bit better use of reserve margins so that we weren't overbuilding in a period of time.

In the April 2003 plan you see the, what was proposed as the reserve margins. The revised plan column, you see that in the year 2005/2006, instead of it being a 24 percent reserve margin, that winter purchase will allow us to come in at the

22 percent reserve margin. But as you notice in all years, we meet or exceed the 20 percent planning criterion.

As far as summer reserve margins are concerned in the April 2003 plan, you notice in 2005 and 2006 we were showing 23 percent reserves and 24 percent reserves respectively. The purchase will allow us to bring that down to 21 and 22 percent reserve margins respectively, and once again meeting 20 percent criterion in all years.

The next slide shows the new additions' status. The Hines 2 combined-cycle unit is currently in its final stages of construction. And if I'm correct, we'll be going through test fire on Units, on both of the Units A and B turbines on the combined-cycle 2 this month and it will be running commercially by December of 2003. It's on schedule and currently under budget.

The winter-only purchase, 188 megawatts. We've combined two sources: Reliant's Vandolah units for 158 megawatts, and Reedy Creek is providing us 20 to 30 megawatts off of their units that they own for the winter purchase in 2004.

Hines 3 combined-cycle, the determination of need has been granted. Governor and Cabinet consideration is, I believe, scheduled for this coming week.

Peakers 1, 2 and 3 will be installed in December of 2006. We're currently looking at build versus buy analyses for units that are currently available on the market. We're also looking at site selection activities so that we can be prepared for construction when time becomes necessary to get construction underway.

Hines 4, the Hines 4 combined-cycle unit, an RFP is currently being prepared under new bid rule requirements. The Hines 4 RFP will be issued sometime in the September/October time frame. There will be a preissuance bid meeting according to new bid rule requirements, and all other bid rule requirements will be maintained. There will not be a significant amount of difference in between the Hines 2, excuse me, the Hines 3 RFP and the Hines 4 RFP since the Hines 3 RFP contained a lot of the information that was already necessary in the new bid rule.

In summary, Progress Energy Florida's ten-year site plan satisfies the reliability criteria in all years and provides sufficient capacity for peak load conditions in all years.

Fuel diversity and generation mix has always been a concern for Progress Energy. Our current plan provides an adequate and reliable service under all expected load conditions.

Now as a segue into the next presentation -- if you have any questions, I'll be glad to answer them first.

CHAIRMAN JABER: Commissioners, do you have any questions of Mr. Crisp at this point?

Go ahead, Mr. Crisp.

MR. CRISP: Okay. As a segue into the next presentation, as I said, fuel diversity has always been a concern for Progress Energy. One of the things that we do is we monitor regional activities for development, and we're keying off several slides that you've already seen this morning.

FRCC has shown you a couple of variations of this slide, and this slide shows the energy sources for the load-serving entities, energy sources for the utilities in 2002 and 2012.

As you can tell, the gas energy supply in 2002 is approximately 28 to 29 percent. So 28 to 29 percent of all energy is going to come from gas in 2002. In 2012 it's approximately 52 to 54 percent of the energy is coming off of natural gas-fired units.

And to broaden the scope a little bit, from the North American gas supply perspective, from some of the consultants that we work with we've gathered a lot of information about their perspectives on what's going to happen in North America. They're projecting the demand for natural gas to be about 67 bcf per day in 2004. Their forecasts are showing growth and demand of about 1.7 to 2 percent per year up to 74 bcf per day in 2010. Now that's an increase in demand of about 10 percent, increasing demand of natural gas utilization of about ten percent between 2004 and 2010. The concern comes here in light of the fact that there is a lot of talk about what's going to be done to increase supply, whether it's mid-continent pipelines or it's drilling in Alaska or drilling in parkland, but nothing has to date been done to increase supply. So one of our consultants has been looking at what happens if nothing is done to increase supply. How big does the gap grow between demand and supply out until 2010? And what they're projecting is that by 2010 there will be a 12 percent gap in between demand and supply. In other words, supply will be, supply will be 12 percent less than demand will in 2010 if we don't go ahead and get additional supplies operating.

Now how does that manifest itself? What it does is it causes a significant effect on gas prices as you've seen in the volatility periods. For the winter months of each one of the previous years you've seen some significant volatility in gas pricing.

This next curve, if you'll bear with me for a moment, I'll explain each one of the lines. Let's go to the bottom line first. It's a blue line and it's the projection for coal prices on a dollar per MMBtu basis. It increases very slightly over the years, and that's based on some of the coal, coal mining projections and transportation projections of escalation.

The next line up is the red line. The red line is a natural gas base case curve. That's what we, Progress Energy, expects to happen with natural gas prices. Why is there such a big decrease in between 2003 and 2008? The consultants are saying basically that these -- the new supply opportunities, mid-continent pipeline, LNG, drilling in forestlands or in parklands is going to become available, that the Administration is going to pursue these new resources and is going to be successful in pursuing these new resources. And if they do that, then the supply will increase and prices will come down.

It's interesting to note that the next line up, the magenta line, which is a hashed line, that's a break-even line. That's the break-even point where if gas reaches that price, it's more economical to build a coal plant to supply the needs.

And herein lies the crux of the issue. If you look at the red line, which is the base case curve, and then you look at the top curve, which is a high gas price curve, you see under high gas price conditions it is more economical to build a coal plant. So we're caught right smack in the middle between a base case issue and a high price issue of do we build a coal plant or not.

Flip over to the next page, please.

CHAIRMAN JABER: Does that --

MR. CRISP: Yeah.

CHAIRMAN JABER: Your statement, does it include the other costs associated with coal, the environmental issues -- sorry about that.

MR. CRISP: No problem.

CHAIRMAN JABER: The environmental issues associated with coal.

MR. CRISP: It does not include the environmental risks. And that's going to be -- we'll talk about that a little bit on down. But that's a good question and it is a big risk and a big concern for us.

CHAIRMAN JABER: Mr. Haff.

MR. HAFF: I also had a question on the previous slide.

What's the approximate price differential between base case and high case? How many percent higher is high case?

MR. CRISP: Good question, Michael. I'd say that's about 30 percent higher. So you're probably talking on average in between -- let's say you look at it on a sustained basis over time. You're looking at an average of around maybe four bucks and a half versus an average in the range of six bucks and a half. Okay?

The bus bar graphs, these are pretty important because what it shows is how does pulverized coal stack up against combined-cycle. And I think, Madam Chair, you were asking questions about nuclear and how that might tie in. And what I would try to do is I'll try to explain that as well with this graph.

CHAIRMAN JABER: Thank you.

MR. CRISP: The graph on the bar is combined-cycle. Red is the capital cost or the cost to build, yellow is the O&M cost and blue is the fuel cost, and all of those add up to a levelized dollar per kW year cost of operating, building and operating that unit. So this is an all-in cost comparison that you might look at and say, okay, do I want to build combined-cycles, do I want to build coal or do I want to build nuclear?

Nuclear would be about, I'd say about 10 percent to 15 percent higher than pulverized coal right now. The reason, that's a very -- that's a fairly aggressive number compared to some of the older numbers you've seen. We've been working with Westinghouse on some of their advanced AP600 and AP1000 units, and what that requires is some government funding. It also requires a program where Westinghouse builds tandem units and they capture economies to scale. So in order to, to achieve those economies to scale, you have to build several of those nuclear units.

CHAIRMAN JABER: Does the spent fuel issue impact the costs at all?

MR. CRISP: Yes, it does. It assumes --

CHAIRMAN JABER: Yeah. I read, I read very recently, I think it was Progress that's looking at on-site storage facilities.

MR. CRISP: Right.

CHAIRMAN JABER: Will that help mitigate the concern?

MR. CRISP: It helps with our Carolinas issues for the time being until Yucca Mountain becomes a reality.

Right now you see on this graph, the difference in between the two bars is what would the increase in gas prices need to be to make coal economical, and that's about a, it's about a 20 percent increase in gas price right now. That's where, you know, if you looked at that previous line, that would be about a 20 percent increase in that line to get us to the point where coal would be, or coal would be an economical resource to build.

CHAIRMAN JABER: Commissioner Deason.

COMMISSIONER DEASON: Yeah. I have a question. Do these numbers significantly change if you assume a higher capacity factor?

MR. CRISP: Yes, they would. Yes, they would. Higher capacity factors as well as improved efficiencies on the coal units and possibly for the different locations. The different locations for coal is very important because rail costs make up a significant component of the fuel cost for coal. So if you reduced any one of the capital costs or the O&M costs through efficiencies or the fuel or transportations costs on coal, it may bring you closer to the break-even point.

And if you increase the capacity, factor utilization, it could have a positive, positive or a negative impact on the utility depending on the utility and what their current utilization of their base load fleet is because you're comparing to a combined-cycle that runs in the 60 to 70 percent capacity factor. Do you want to run a coal unit at 60 to 70 percent capacity factor? Not really. You want to run them as much as you can.

COMMISSIONER DEASON: That's what I would assume that you would -- if you're going to incur the higher capital costs, you probably would want to maximize the benefits from the lower stable fuel costs and you would have a higher capacity factor.

MR. CRISP: Yes, sir. And the coal plant obviously gives you the natural hedge against the gas volatility pricing year by year.

COMMISSIONER DEASON: I have another question on the O&M cost. Just looking at the magnitude of the area that is in yellow, which I believe is O&M, it appears that the O&M is higher for the combined-cycle, and I thought that it was just the opposite, that O&M costs were higher for a coal unit. Could you explain that differential?

MR. CRISP: O&M on combined-cycle includes, it includes firm price transportation for the combined-cycle unit and that's why that number is higher.

The firm component that you have to lock into on the gas pipeline is added into that O&M component. That's where it adds up higher to the coal unit.

COMMISSIONER DEASON: Okay. And I have another question on the capital cost. In any study like this you have to make a lot of assumptions and I understand that. And one of those assumptions would have to be cost of capital.

It appears that right now interest rates are fairly low and they may or may not continue, and I would assume that part of the capital required to construct either one of these hypothetical plants would be partially made up of debt as well as equity. What, what type capital costs did you assume for this comparison?

MR. CRISP: I will have to get back to you with that one, Commissioner Deason. I would assume that it was our normal cost of capital that we're currently using within our RFPs. I believe that's in the 8 to 9 percent range, but I'm not sure. Let me get back to you on that so that I can --

COMMISSIONER DEASON: Okay. You can just provide that to staff.

MR. CRISP: Certainly.

COMMISSIONER DEASON: But all other things being equal, the lower the cost of capital, the more attractive our higher capital cost unit becomes, everything else being equal; correct?

MR. CRISP: Exactly. That's correct.

From a discussion perspective, will gas coal price differential occur and hold? What we're looking through in our study is we're seeing that if there is a sustained delta in between delivered coal and delivered natural gas of $3.75 in MMBtu, then it is more cost-effective to build coal. In other words, if gas is sustained at $3 in MMBtu or, excuse me, if coal is sustained at $2 in MMBtu, then gas is sustained at $5.75 in MMBtu, it would be more cost-effective to build the coal unit.

LNG expansion -- LNG and the other, the mid-continent expansion and other drill sites will continue to be worked. The Administration is supporting of that. Will they continue to be developed and possibly undercut coal prices? That's a risk. That is something that we have to continue to assess and to continue to study. The gas marketers will continue to monitor and try to price their product as closely as they can to that break-even point. And when they hear that coal development is on the way, then you may see their prices come down a little bit. But they're going to do everything they can to maximize their revenues out of the assets that they currently hold from the gas pipeline perspective and the gas ownership perspective.

Our current Administration will continue to sponsor gas development, and historically spot coal volatility has mirrored the gas spikes just simply because the markets are interrelated and you're looking at a final converted energy price.

Gas markets will react quickly and, in fact, they have reacted quickly in the past two coal development announcements.

CHAIRMAN JABER: Does the Department of Energy still offer the clean coal technology grants?

MR. CRISP: I'm not sure about that, Commissioner Jaber. We'll follow up on that and get back with you on that one.

CHAIRMAN JABER: I'm just wondering if they're still available -- if they're still being offered and if there are funds still available.

MR. CRISP: Uh-huh. I know one of our issues is to go back into the Department of Energy and start seeing whatever kind of opportunities we may be able to take advantage of to see if you can break that cost down on the coal units.

CHAIRMAN JABER: Thank you.

MR. CRISP: One of the things that has become evident is over the years there's not been that much coal development, so the engineering procurement and construction skills that go along with building coal plants are somewhat in demand out there and there's not that much of a supply of them.

The TVA and midwest areas where coal is much less expensive because they are basically at the mine mouth, those are the areas that you would expect to move first and build coal plants quickly. Their base case gas forecasts are at a break-even point right now roughly because of the lower delivered price of coal. And that's largely why those areas, the areas around Powder River Basin up through the Alliance region and through TVA, because of their proximity to coal plants, that's why they do go ahead and lean towards building coal rather than building natural gas units.

So in summary, from our standpoint, Progress Energy Florida pros for coal development. We do have base intermediate generation needs, and coal is right in there in the mix. It's needed to support Florida load growth. Some of our high gas forecasts already suggest that coal may be economic.

Cons against coal development is that coal is not economic under our current base case forecast. There are some high risk issues out there around the sustained price differential that's required to justify and make that coal unit the next least cost unit, and there are those high cost risk issues around environmental uncertainties associated with coal.

So in going forward we've prepared two alternative paths to look at. Should we --

COMMISSIONER DEASON: Excuse me. Could you go -- I have a question on the previous, not the -- the previous slide to the previous slide. If you'd go two back, please.

The very last bullet point there, you're making the point that in the TVA midwest area you would assume that that would be the area of the country that would more likely begin building coal plants because of the lower cost of coal at the mine mouth; correct?

MR. CRISP: That's correct.

COMMISSIONER DEASON: And they're basically at kind of a break-even point at this time?

MR. CRISP: Yes, sir.

COMMISSIONER DEASON: Do you know of any significant coal plants that have been announced for that area as of yet?

MR. CRISP: Not yet, because all of those areas are in a surplus generation. The reserve margins in both of those areas are well into the high 20s, maybe even up to 40 percent reserve margins in those areas because of overbuild of gas units. There's going to have to be some shakeout there before they really get serious about building a coal plant.

The other side of that argument is if each one of these utilities is looking at their, their mix and saying, well, I don't want to expose myself to future gas volatility, then now is the time to go ahead and build. They have not -- there has not been a significant amount of announcement yet though. And the point there is if we see something soon, it'll come out of that region.

So we have two alternative paths going forward.

Should we introduce coal into the Progress Energy Florida expansion plan? One thought there is to issue an RFP which would accommodate coal unit construction schedule. It's not our next planned unit. It's not Hines 4, it's not Hines 5. It would probably be something like Hines 6 in the 2011 time frame. But concurrent with that RFP we would have to address the risks and the issues that we've talked about previously, which are recovery issues from the regulatory standpoint, the least cost perspective, what if gas prices do come down while we're developing a coal unit, and the emissions issues, particularly carbon dioxide and mercury. Those are two issues that are probably on the forefront.

The other alternative would be to maintain current gas expansion plan. That's based on what could be done for supply and availability. That would have to be addressed at the national level. It currently is being addressed. Pricing could be addressed at the regional or territory level, and some of the tools there could be contract terms, hedging programs, things that we could use with the Commission's backing to hedge and lock in on gas prices for the long-term. But those two have to be handled hand in hand, both have to be achieved, because if supply and availability is not handled, then the prices are going to skyrocket and we're going to be slave to the situation with the volatility gas pricing.

Any questions?

CHAIRMAN JABER: I hate that you ended it on that note.

Commissioners, do you have any questions of Mr. Crisp?

There was a slide that you used to make the point that there was the 12 percent gap between the supply and demand. I didn't, I did not fully appreciate that slide. Could you go, just take me back quickly through it?

MR. CRISP: Yes. Slide Number 3. Yes.

What this slide tells us is that if there is no additional development done to increase the supply, and I'm talking molecules, I'm not talking about delivery or pipelines, I'm talking about pure molecules, if no additional work is done, we're going to begin to tap out over the existing capacity and capability of our existing wells. So not only are we facing a period of time where demand is going up, but the actual supply of molecules is going to start to slightly decrease. So by the end of 2010 we'll be looking at roughly a 12 percent deficit in supply in order to meet daily demand.

CHAIRMAN JABER: Okay. So does this take into account then pipeline capacity, transmission issues, your, all of your units?

MR. CRISP: We're looking purely at the molecules and the pricing.

CHAIRMAN JABER: Okay.

MR. CRISP: Yeah. We've kind of taken a different approach from FRCC, who is looking at pipeline issues and things like that. We're looking at price, least cost.

CHAIRMAN JABER: And that's it.

MR. CRISP: And the supply of the molecules.

CHAIRMAN JABER: Okay. Thank you.

MR. CRISP: You bet.

CHAIRMAN JABER: Thanks for your presentation.

MR. CRISP: You bet.

MR. HAFF: May I ask a question before he leaves?

CHAIRMAN JABER: Mr. Haff.

MR. HOFFMAN: Sort of a general planning question. We've heard some discussion, I guess, in the FRCC presentation regarding that there's not a lot of retired units proposed for retirement in any of the ten-year site plans. I know you don't have any at this time. Does Progress Energy do any sort of analysis, a cost-effectiveness analysis of retiring older plants and replacing them with newer ones?

MR. CRISP: You bet. Every year we go through when we're doing our ten-year site plan, we're looking at units on a unit-by-unit basis. We take a look at the older units and we analyze them from a cost-to-operate perspective versus their capacity factor utilization. And what we do is when we look at that, we compare them to the cost of, okay, if I have to replace this unit, let's say I want to retire a 100-megawatt unit, how much is it going to cost me to replace that unit? And we do a break-even analysis that says this unit -- currently we spend, we may spend a lot more O&M on it, we may spend a lot more for fuel on it, but so far the capacity cost of a new unit greatly exceeds the increases in O&M versus the increases in fuel.

So that's why we have removed some of our units in the past from the retirement plan is simply because it makes the most cost-effective decision for the ratepayer from that perspective to keep those units on-line.

COMMISSIONER DEASON: I have a further question. You had a slide, I believe it maybe was the last slide or next to the last, and there was, there was a bullet point concerning regulatory risk.

MR. CRISP: Yes, sir.

COMMISSIONER DEASON: And you have it listed as recovery, recovery of cost. I assume that that's in the regulatory sense to allow you the ability to recover the cost; is that correct?

MR. CRISP: Yes, sir. Because -- and it's tied to that second bullet there from the least cost perspective.

For instance, if we start building a coal plant and we, or we do an RFP and perhaps we buy from someone who's going to build a coal plant, we're looking at this from a least cost perspective. What happens if the prices of natural gas do come down beneath that break-even point over time? We would still be -- we might be in the middle of building the coal plant and the risk there would be would the Commission feel that we made an imprudent decision to pursue coal and perhaps not allow recovery? And our expectation would be once we start going down the path of developing coal, we're going to be looking at it from a very long-term perspective as the smartest thing to do to balance the different fuels and would expect recovery of, against that plan.

COMMISSIONER DEASON: Well, let me, first of all, make the observation that, that I can appreciate the concern, but that if that is truly a risk, and I think maybe you're overstating it, but if that is a risk on the coal construction, if you think this Commission is going to be that narrow-minded to look at it, that that's also a risk if you continue to construct gas and gas prices skyrocket, there's a risk on that end as well.

MR. CRISP: Yes, sir. And I respect your statement. We felt it important just to put the bullet down there just to make sure that we included it rather than leave it off. It's very important to put all the information down that we're thinking.

COMMISSIONER DEASON: Oh, and I'm not, I'm not -- obviously it needed to be put there. I'm not, not questioning that. But if you do -- if you were to construct a coal plant, I think we've already determined that probably the largest component of cost are the up-front capital costs.

MR. CRISP: Yes, sir.

COMMISSIONER DEASON: And that once those sunk costs are invested, that most likely that unit would be dispatched at a very high level.

MR. CRISP: Yes, sir.

COMMISSIONER DEASON: And even if coal -- even if gas prices stabilized or even decreased, it probably still would have a high capacity factor, you would agree with that.

MR. CRISP: Yes, sir.

CHAIRMAN JABER: Okay. Mr. Crisp, thank you for your presentation.

MR. CRISP: Thank you.

CHAIRMAN JABER: I've got that FP&L is next, Mr. Haff.

MR. HAFF: Yes.

CHAIRMAN JABER: Commissioners, that would be the black and white presentation that Mr. Walker probably put together.

COMMISSIONER DEASON: He didn't want color to come out of his budget, I guess.

CHAIRMAN JABER: That's right.

MR. SCROGGS: Good morning, Commissioners. Can you hear me?

CHAIRMAN JABER: Good morning.

MR. SCROGGS: My name is Steve Scroggs, S-C-R-O-G-G-S. I am currently employed with Florida Power & Light Company as the manager of integrated resource planning. I appreciate the opportunity to talk about our ten-year site plan this morning. We'll be talking about the resource additions and the considerations that we have folded into our ten-year site plan, and then we'll be talking about our planning standards for loss of load probability and reserve margin and how we will be meeting those over the coming ten years.

Our cumulative capacity additions, over the planning period approximately 6,449 megawatts combined with some repowerings that the Commission is well aware of, changes to some of the qualifying facilities on our system, the new unit additions and changes to some existing power purchases.

Looking out over the next several years we have combustion turbines coming on at Ft. Myers this year, we have Manatee Unit 3 combined-cycle facility coming on-line in 2005, and, of course, the repowering of Martin units adding incremental megawatts not listed on this chart in 2005.

In 2007 we are planning for, in our placeholders planning purposes an unsited combined-cycle unit in 2007. And then in future years, 2008, 2010 and 2012, we have unsited facilities with a placeholder value of around 1,100 megawatts as our expected needs out into those future years.

MR. HAFF: I have a question on that. I guess there's -- an RFP will be coming out soon for that 2007 combined-cycle unit?

MR. SCROGGS: Yes. We're taking all the necessary steps to be ready to make that decision within the month.

MR. HAFF: To release the RFP in about a month?

MR. SCROGGS: We'll be making that decision within a month, yes, sir.

In the future years, 2008 and beyond, you notice that we have essentially said the fuel source is to be undetermined, and that's because we are entertaining and expect to accommodate a wide range of opportunities out into the future. Some of the ones that we're looking at are certainly natural gas, combined-cycle and simple cycle units for their capital and emissions efficiencies, as well as solid fuel facilities, coal or pet coke-based, or LNG sourced generation as there's discussion of that as a, as an alternative source in the planning horizon.

Beyond the planning horizon of the ten-year site plan nuclear is a potential consideration for Florida Power & Light, and we're doing the necessary steps at this stage to understand what the feasibility of that is in the long-term.

As a part of our planning process we recognize the DSM programs that we have in place and our DSM goals out through the planning period. Those goals have been an important part of our programs, and we continue to see those goals grow as we project our load growth on the system in the planning horizon.

With respect to our planning criteria for loss of load and reserve margins, we use those two methodologies as our basis for planning. And our criteria is similar, as stated by others, essentially one day out of ten years or one-tenth of a day per year. Reserve margin, a minimum of 15 percent, of course. But beyond 2000 -- including the summer of 2004 and beyond Florida Power & Light is planning to cover a 20 percent reserve margin in our system.

Our projected values for these planning criterias show that as we move into the bulk of the planning period, we're satisfying both criterias. We'll note that in 2006 you see a 19.8 percent reserve margin in the summer period. We actually will be covering that through short-term purchases. There are some other contracts in play right now that have options on them. And we're not in a position to secure that at this time, but we should by the end of 2004, I believe.

COMMISSIONER DEASON: Excuse me. On that slide I noticed that the, the loss of load probability declined significantly as you go through the years.

What causes that decline? And recognizing a decline is an improvement of, of, of the standard, but it seems to be fairly significant. How is that achieved, realizing that the reserve margin stays relatively constant?

MR. SCROGGS: With our planning -- this involves our transmission planning as well, and our transmission planners have incorporated their expectations for transmission projects throughout this planning horizon as well. So I would -- without having certain background from the transmission side, I would say a good percentage of that loss of load probability is being managed by transmission projects rather than directly impacted by gross additions to generation.

COMMISSIONER DEASON: Well, then to me -- and I can appreciate that. I guess it begs the question though that if you can, can achieve such remarkable loss of load probability numbers, is it necessary for you to continue to have a reserve margin in excess of 20 percent?

MR. SCROGGS: That would be a consideration. I think we see the reserve margin planning standard of 20 percent assisting in a lot of areas, including helping to lower the cost to our customers by being able to bring on more efficient generation as a replacement as another benefit from a reserve margin of that size.

COMMISSIONER DEASON: Well, obviously, I mean, I would agree you would need to look at whatever is the most efficient and the reserve margin may fall out of that. But if we're in a situation of adding higher cost generation which was not significantly more efficient, at some point I think we have to ask the question, is it still cost-effective to have a reserve margin in excess of 20 percent? You would agree that's the question that needs to be addressed in later years?

MR. SCROGGS: I think that's an appropriate question to be addressed, yes.

COMMISSIONER DEASON: Thank you.

MR. SCROGGS: So on a system basis, our system is projected to be very reliable, loss of load probability is extremely low, and the reserve margins are projected to be better than our planning standard. As noted in our ten-year site plan, Section III.C, we do have a growing concern over the imbalance of generation in our southern region, in the Miami-Dade and Broward County regions, as we increase and see increased projections of load growth in that area but haven't sited generation in that area. We're addressing that in our upcoming planning and want to make sure that we maintain efficient options available for generation additions in the system as we go forward.

CHAIRMAN JABER: Thank you, Mr. Scroggs.

Commissioners, do you have any questions? Mr. Haff.

MR. HAFF: Thank you.

CHAIRMAN JABER: Thank you. I have that the next presenter, Mr. Haff, is Gulf.

MR. HAFF: Yes, Gulf Power Company.

MR. MARLER: Good afternoon. My name is Mike Marler;

I'm with Gulf Power Company. I'm primarily responsible for Gulf's forecasting, and I'll be presenting that part. And this is my colleague Homer Bell. He'll present the generation expansion plan.

CHAIRMAN JABER: Mr. Marler, you have the first part of the presentation?

MR. MARLER: Yes, ma'am.

CHAIRMAN JABER: Okay. Go right ahead.

MR. MARLER: This depicts our summer peak demand growth. Historically we've realized the 2.9 percent compound average annual growth rate. Our previous forecast had projected a 0.1 percent growth based on that last historical data point which is not a weather normalized value and so it's kind of misleading. Our new forecast has been revised upward just slightly in the short term due to model calibration and in the long term due to some additional customer growth. The long-term growth becomes 0.5 percent.

Our winter peak demand forecast historically has presented a 3.7 percent compound average annual growth rate. Our current forecast is just slightly lower than the one we had last year. Both of them right around 0.6, 0.7 percent compound average annual growth rate in the projected growth years. And it's a little bit misleading there as well because the historical growth is based on that low data point in 1993 which was mild weather driven.

The net energy for load projections reflect a 3.1 percent historical growth. The forecast -- the new forecast expects a 1.1 percent growth rate over the next ten years compared to a 0.7 percent growth in our previous projections.

The next chart depicts our DSM savings that we've realized. Through 2002 we've managed to save a total of 294 megawatts of summer peak demand, and we expect that to grow to a total of 478 megawatts by the end of the planning horizon. The historical growth rates have been 2.9 percent after DSM savings, would have been 3.1 percent historically, and with a forecast horizon we're expecting those to be dampened to 0.5 percent from what would have been 1.1 percent.

Winter peak DSM savings historically have been 3.7 percent. Again, that's influenced by that low data point in 1993. Over the forecast horizon, what would have been 1.3 percent is going to be dampened to 0.6 percent due to additional DSM. And the actual savings by 2002, we've realized a total of 342 megawatts reduction in winter peak and that will grow to about 554 megawatts by 2012.

Net energy for load basis, historical growth has been 3.1 percent. We expect it to be about 1.1 percent over the forecast horizon compared to what would have been 1.2 percent absent the DSM programs. The net gigawatt hour savings represented by this is 623 gigawatt hours by 2002, and we expect that to grow to a total of 905 gigawatt hours by 2012. And that concludes the forecast part of it. If you have any questions over any of it, I'll be glad to answer them.

CHAIRMAN JABER: Thank you. I think we're ready for the second part.

MR. BELL: Good afternoon, Commissioners, staff. My name is Homer Bell; I'm an engineer in generation services for Gulf Power Company. And I would like to review you our current capacity plan for additions and the retirements that impact our capacity available to serve the load that Mike Marler has talked about.

I have a chart here showing over the ten-year horizon what Gulf plans to see as far as additions and retirements. Our installed capacity does exclude all units -- or include all units except Scherer 3 which is sold off system. You notice in this current year and through 2005 our reserves, especially in 2003 through 2004, our reserves are adequate to meet our load growth projections.

We have some interruptible capacity -- that's in the second column -- as well as some purchased power capacity. In 2003 and 2004 our purchased power contract will expire, that's 19 megawatts, will expire in 2005. So it will not be available for summer load service in 2005. But we begin to have a slight need for capacity in 2006. Southern electric system, in order to maintain the 15 percent reserve margin that we planned for, the generation mix studies are calling for peaking capacity to begin to be needed. And Gulf plans in 2006 at this time to meet that need with a short-term purchase.

And you'll see in the second column there that the short-term purchase plus the interruptible capacity that we have is 177 megawatts. That short-term purchase will be approximately 150 megawatts.

CHAIRMAN JABER: Is it possible that the PPA that expires in 2005 gets renewed?

MR. BELL: Commissioner, I believe we'll take a look at that. It's a cogeneration contract, negotiated contract. I don't know where that stands. We would hopefully like to take a look at that and some other opportunities that may present themself in that time frame.

But as we enter into 2007 -- let me back up. One thing I should note that in the capacity addition column there, you'll note some negative numbers. Those are reflective of our retirements of Crist 1, 2, and 3. So considering that, it is a factor that impacts our need for capacity in 2007.

Our plan at this time is to install two 157-megawatt CTs for service in June 2007. That will give us adequate reserves to serve system load until approximately 2010 when we will be adding short-term purchases to cover our need in that time period.

And so, as a summary, we have retirements. We did actually retire Crist 1, 24 megawatts, as of March 31st this year. Units 2 and 3, 24 megawatts and 35, respectively, will be retired in May 2006.

We are proposing that we add combustion turbine capacity in June 2007, and then later on out in the planning horizon, around 2011, the end of 2011, we will retire Scholz 1 and 2. That concludes my summary of capacity additions and retirements for Gulf Power Company.

CHAIRMAN JABER: Commissioners, do you have questions of Mr. Bell?

COMMISSIONER DEASON: Yes, I do.

CHAIRMAN JABER: Commissioner Deason.

COMMISSIONER DEASON: In the year 2005 you show a 10.2 percent reserve margin for Gulf, but also there's a 15.9 percent reserve on the Southern system, and the criterion is 15 percent. So there appears to be more than adequate reserves on the Southern system. Does Gulf anticipate relying upon the Southern system to meet any anticipated needs that could result from extreme weather or a unit-forced outage?

MR. BELL: That's correct, Commissioner. We conduct on a periodic basis studies to determine what that adequate -- the adequate level of reserves are, and in that look, we do consider our pattern of weather over a number of historical years. So that 15 percent would be reflective of, you know, what we think it takes to meet load, what kind of reserves, what level of reserves are required to meet load considering that abnormal weather. And we would in this time period rely on the Southern electric system to meet our load.

COMMISSIONER DEASON: Have you done an analysis or an assessment of the adequacy of transmission in the event that you would have to rely upon significant imports from the Southern system?

MR. BELL: I'm not -- at this time I'm not aware that we have. I can find out. I'd be happy to follow up.

COMMISSIONER DEASON: Could you share that with staff? I would appreciate that.

MR. BELL: Yes, I sure will.

CHAIRMAN JABER: Mr. Bell, with regard to the other Southern systems, are they in the similar -- are they in a similar situation as the Gulf system for the year 2005 and 2006? Are they -- Alabama comes to mind and some of your -- just the Southeastern systems. Do they rely on Southern with respect --

MR. BELL: Yeah, well, we plan to meet a total system load, and that's all the operating companies of the Southern electric system: Gulf, Georgia, Alabama, Mississippi, Savannah Power -- Electric and Power and Southern Power. So we are -- have a coordinated planning approach. And from time to time, they may be the one that another operating company may have a greater need as compared to the other companies, and they would be adding capacity in an amount that was appropriate to move their targeted reserves up to, you know, the appropriate level.

CHAIRMAN JABER: We've had so many just Southeastern storms and outages the last couple of years. Do you take that into account with regard to the needs of the entire Southern system, and how -- you know, do you rank your needs with regard to the states?

MR. BELL: I think -- no, I think what we do -- as the system, we look at it -- you know, what's the appropriate level of reserves on the system. Then we have a methodology that will ensure that all companies can meet their load, and some companies will be short in some years as compared to others. But we will plan to, you know, add our appropriate share of reserves when the mix -- not the mix but the methodology requires it.

CHAIRMAN JABER: At what point do you think the company, Southern, as a whole starts looking at whether the individual system reserves should be as close to 15 as possible?

MR. BELL: Generally we plan all to have an equal reserve margin of 15 percent. What makes that vary, as you see here, is the consideration of what is the economical block size of capacity to add. So we are driven to have equal reserves, and that is a goal of the Southern electric system.

CHAIRMAN JABER: Okay. You don't have -- the company again, Southern, as a whole doesn't have a target date for achieving individual system reserve margins of 15 percent?

MR. BELL: On an annual basis, I believe it's -- I mean, that's the goal, but there again, look at capacities that are planned for -- you know, come on-line. And it may be that companies that -- there may be some companies that do have a lower reserve margin. So I don't know. I do not know if there's a set time. On an on-going basis, we try to meet that.

CHAIRMAN JABER: Okay. Thank you.

Staff, did you have any questions?

MR. HAFF: No.

CHAIRMAN JABER: Thank you both.

MR. BELL: Thank you.

CHAIRMAN JABER: Commissioners, we're going to take a one-hour lunch break. And if I've done my math correctly with staff's agenda, we'll have just a little bit over an hour left to do. So I think we can take a one-hour lunch break, come back here at 1:25.

(Lunch recess.)

CHAIRMAN JABER: Okay. Let's get back on the record. We left off with TECO's presentation. And, Commissioners, we may not have access to the computer on this presentation, but you've got the handout from TECO we can follow. So with that, let's get started.

MR. SMOTHERMAN: My name is William Smotherman; I'm with Tampa Electric Company. I am the director of resource planning for the company. And today, I'd just like to give a quick overview of our 2003 ten-year site plan.

If you turn to the first page, it's labeled, "Summer Total Retail Peak." That page shows a graphic of our summer peak demands. It shows historically from 1990 through 2002, and it shows forecast values for 2003 through 2012. You'll notice in that graphic that the 2002 forecast is labeled as a star, and the 2003 forecast, the present forecast is the diamond -- it's not diamond, it's the triangles. And history is shown by the squares. Essentially you can see by looking at the graph there's not a large amount of change between our '02 and our '03 forecasts. Likewise, from a historical standpoint, relatively the load growth is pretty similar to what we've experienced in the recent history.

If you turn to the next page in the presentation, it's labeled, "Winter Total Retail Peak." It's a similar graphic displaying the historical as well as the 2002 and 2003 retail peak demand forecast for our system. And again, the '02 and the '03 forecasts are fairly similar. In the historical numbers, you'll notice there is a lot of up and down in those numbers and that is really related to what our winter temperature happens to be at any particular historical period in time. As you know, winter peak load is very temperature-dependent. So as that -- whether we actually have winter temperatures or not will radically change those numbers.

If you flip over to the third slide, it's labeled, "Demand-Side Resources." And this slide merely depicts for our present forecast how much of our load is made up from demand-side resources. You'll see presently for the summer of '03 we have 620 megawatts. For the summer of 2012 that would increase to a number of 689. Relatively you'll see that the percentages on each of the pieces are fairly consistent. We're seeing really the most growth in the conservation area. That's going from about 15.6 up to about 18 percent.

The other areas are fairly consistent. There's a slight drop on a percentage basis in load management. That's a drop on a percentage basis from an actual number basis. Those numbers are actually increasing. Interruptible numbers are actually dropping. They're going from 29 percent to 25.4 percent, and that's merely due to a projected reduction in the phosphate load over time merely because phosphate is being mined out of our territories in Tampa Electric's service area.

Flip over to the next slide. It's got the same title as the previous slide. This just depicts the winter demand-side resources versus the last one depicted for the summer peak time period. That is growing from 11,170 to -- not 11,000, I apologize. It's 1,170 to 1,446. Again, the trends are fairly similar. Largest growth there is from conservation programs. Interruptible is reducing again merely because of the reduction in the phosphate load.

The next graphic is titled, "System Reliability." And this depicts the comparison of our expansion plans and reserve margins that result from those plans in the '02 ten-year site plan and the '03 ten-year site plan. As far as future additions of capacity that are shown on that table, we have some timing differences in capacity. Those are related to small changes in our demand-side as well as our load forecasts. But you'll notice that essentially we have a CT added every year except for 2011, and in the prior ten-year site plan, we didn't have a CT added in '06 or 2012.

The other noticeable difference here is the reserve margins for 2003 and 2004. We had a 26 percent summer reserve margin forecast for the 2002 ten-year site plan and that's down to 17 percent. And relatively we had a 37 percent forecasted for the summer of 2004 and that went down to 20 percent. The basic driver for that is the revised shutdown date for the Gannon station units. We presently have revised the date for Gannon 1 and 2. They were shutdown as of early April of this year. Gannons 3 and 4 will be shutdown this fall. In the prior ten-year site plan, all four units had been left on-line until the fall of '04.

CHAIRMAN JABER: Commissioner Deason.

COMMISSIONER DEASON: Yeah, I have a question. The column entitled, "Reserve Margin With Load Management And

Interruptible," for those calculations how do you treat load management and interruptible?

MR. SMOTHERMAN: Those are treated as a reduction to our system demand, so our system peak.

COMMISSIONER DEASON: So you take the system peak and you reduce it by load management and interruptible to get a firm system peak?

MR. SMOTHERMAN: That's correct.

COMMISSIONER DEASON: And then you take that and divide it by firm capacity; is that correct?

MR. SMOTHERMAN: It's the firm capacity minus the firm system peak, and that quantity --

COMMISSIONER DEASON: The outcome is the numerator.

MR. SMOTHERMAN: Yes.

COMMISSIONER DEASON: All right. Thank you.

MR. SMOTHERMAN: The following graphic labeled, "Integrated Resources," this is for the summer of '03, and it also depicts the summer of 2012. What this depicts from a station perspective as well as a general resource perspective, what percentage each of these resources mean to us now and what they will mean to us in the future as well as the relative growth of our resources. So you'll be able to see relatively the Big Bend station, which is a coal-fired station, our present Gannon station, Polk, and Bayside, which basically consists of Bayside 1, which is the first phase of the Gannon conversion. We also have firm purchases on there. Other which represent some cogen and other contracts as well.

And then you'll see as that grows through 2012, Bayside represents a much larger portion of that. That's with the integration of both the Bayside 1 and Bayside 2 units. Plus it includes siting a couple of CTs at the Bayside facility. The Polk facilities also grow and that's related to siting CTs at the Polk facility. There's a unspecified future capacity segment of that pie. That essentially represents future CTs that are in the plan but do not have -- have yet to be sited.

If you turn over to the next page, there's another graphic related titled, "Integrated Resources." This is an identical graphic to the previous one except it depicts our integrated resource picture for the winter of '03 and a winter of 2012. Essentially the percentages are fairly similar. You'll notice that demand-side reduction represents a much larger piece of the pie in the winter numbers than it does in the summer numbers, and that is really related to the types of programs which we've implemented tend to have higher megawatt results for us in the winter than they do in the summer.

The next graphic is titled, "Generation-By Fuel Type." And this shows the energy side -- the other slides that we -- the two previous slides I showed depicted the capacity side of it, and this shows the energy side of it. And essentially each of the pieces of the pie here represent different types of fuel production. The coal/pet coke piece of the pie is -- represents coal that's burned either at Big Bend or at Gannon and pet coke that is burned at Big Bend or Gannon. The syngas slice --

CHAIRMAN JABER: Mr. Smotherman, can I interrupt you on the pet coke before you move on?

MR. SMOTHERMAN: Yes.

CHAIRMAN JABER: Didn't you have one of the Department of Energy grants or no?

MR. SMOTHERMAN: Yes, we did for the Polk 1 unit.

CHAIRMAN JABER: Do you know if they still offer those grants, and if they do, is there money still available for Florida companies?

MR. SMOTHERMAN: I don't know where they're presently sitting in that program, so I can't say if they are or they aren't presently. I know in the recent past, past couple of years they had, but I don't know where the program sits presently.

CHAIRMAN JABER: When did you get the grant?

MR. SMOTHERMAN: I don't remember exactly when it was granted because it was -- we essentially took over a project that was done -- was going to be done by another utility. But we installed our plant and started essentially reaping the benefits of that back in '93 -- I mean, '96. I'm sorry.

CHAIRMAN JABER: Do you remember how much money was available to you?

MR. SMOTHERMAN: Not exactly. I want to say on the order of 100 to 200 million, somewhere in that range.

CHAIRMAN JABER: Thank you.

MR. SMOTHERMAN: But this graphic essentially depicts our coal. Syngas represents the Polk 1 facility which essentially burns both coal and pet coke as well. We show the purchases and natural gas percentage. You'll notice that there is a significant increase in natural gas, and essentially that increase is driven by the addition of the Bayside combined-cycle units.

The next page of the presentation is titled, "2005 Request For Proposal." And essentially Tampa Electric has issued an RFP that was just issued recently. The RFP was issued to get peaking -- firm peaking power proposals to compare to our self-build option for our May 1st, 2005 CT. That RFP was mailed to 23 potential bidders. It was also advertised in Platt's Megawatt Daily, and responses are presently due August 21st of this month.

What we will be doing is once we get those responses, they'll be evaluation that occurs, and based on that evaluation, we'll make a determination of whether we will construct our planned unit or whether we will take advantage of a purchased power opportunity.

In summary, Tampa Electric's 2003 through 2012 ten-year site plan, we believe, provides an adequate system reliability and overall fuel diversity for our customers. And that concludes my presentation. Do you have any other questions?

CHAIRMAN JABER: Commissioners, do you have questions?

Staff?

MR. HAFF: I just have one. Mr. Smotherman, just generally speaking, when you are looking at an expansion plan that goes out ten years as all the utilities do, how do you-all determine the cost-effectiveness of, say, retiring an older unit and replacing it with a newer one? How is that done as part of the planning process?

MR. SMOTHERMAN: Okay. Essentially we look at what the cost is of the older capacity that we may have. We don't necessarily look at that on an annual basis. It's more something that's looked at for older capacity like the Gannon units. And determinations are made based on how much it costs to run the plant and upkeep the plant and operate the plant essentially versus how it's operated.

MR. HAFF: Thank you.

CHAIRMAN JABER: Thank you for your presentation.

Staff, I have -- the next round of presentations will be in the following order: FMPA, GRU, JEA, Lakeland, OUC, Tallahassee, Seminole. Any changes to that?

MR. HAFF: No, ma'am.

CHAIRMAN JABER: Okay. Then we're ready for FMPA.

MR. MAY: Good afternoon. My name is Bill May; I am the planning supervisor for FMPA. And I thank you for having us here.

Give you a little bit of background for the benefit of those that were not here last year. FMPA is a 29-member municipal electric utility coordinator, if you will, a joint action agency. We have five power supply projects: The St. Lucie in which there are 15 members that participate there. We combined have 74 megawatts of that generation. The Stanton 1 and 2 in which six members participate in the coal units that are there. The Tri-City project which is 23 megawatts, and there are three of the members that participate in that. And the Stanton 2 which are the Stanton A combined-cycle unit which is 99 megawatts and seven members participate in that. All together there are 15 members that we supply their total load or the all-requirements members.

From 1997 to 2000 we increased from six cities to 13 cities as members. In 2002, last year, we added Lake Worth and KUA at the end of the year. As a result of that, the summer peak demands looked somewhat skewed. In 2002 our actual summer peak was 992 megawatts. In -- at the end of the year, we were including KUA and Lakeland. As a result of that, our projected peak for this summer is 1,419 megawatts and for next summer is 1,454 megawatts or a growth of 2.5 percent.

The significant changes between the 2002 and 2003 ten-year site plans were, of course, the additions of KUA and Lakeland which resulted in that increase of approximately 400 megawatts in our peak demand. In 2007 we have a combined-cycle that we actually -- combined-cycle unit that we actually increased from 200 megawatts to 250 megawatts. In 2011 we have a 165-megawatt CT that I believe in the 2002 ten-year site plan was shown as 2010. And we moved the in-service date of a unit, 22 megawatts, at Key West to 2006.

In our ten-year site plan, we have a couple of conservation programs. We have demand-side management in which we have direct load control at both Ocala and Leesburg. We are currently evaluating that program. Other programs also include by the cities individually are residential, commercial, and industrial energy audits.

Under renewables, we still participate in the utility photovoltaic group, and the landfill gas-burned station at the Stanton plant is still functioning.

Other supply-side alternatives include cogeneration projects at Leesburg and Clewiston which are Coca-Cola and the USSC, the sugar plant that's there.

Florida Municipal Power Pool is -- has been in existence since 1988. The members of the power pool are OUC, Lakeland, and FMPA. And our goal in operating this power pool arrangement is to share the benefits of being in the pool and attempt to minimize the cost of all of our operations. That concludes my presentation. Do you have any questions?

CHAIRMAN JABER: Commissioners, do you have any questions for Mr. May?

Staff?

MR. HAFF: No.

CHAIRMAN JABER: Thank you for your presentation. Gainesville Regional.

COMMISSIONER DAVIDSON: Go Gators.

MR. KAMHOOT: Thank you.

MR. KEATING: We're in hostile territory.

COMMISSIONER DEASON: Where do you want him to go to?

MR. KEATING: Isn't it crocodiles now?

(Laughter.)

COMMISSIONER DAVIDSON: If staff could identify everyone in the audience who's hissing and clapping and laughing, that would just be great.

MR. KAMHOOT: Good afternoon. My name is Todd Kamhoot, and I'm here representing Gainesville Regional Utilities. Is this the proper orientation since I can't see it up there? Is that right? Okay. Thanks.

GRU is a summer-peaking electric system, largely the result of the penetration of natural gas in our service territory. So I'll be speaking today largely with respect to our summer peak loads.

All right. GRU has 610 megawatts of net generating capacity consisting of 228 megawatts of coal-fired steam capacity, 106 megawatts of gas-fired steam capacity, 37 megawatts of waste heat steam capacity, 228 megawatts of gas turbine capacity, and 11 megawatts of nuclear capacity.

Last year, GRU generated 204 gigawatt hours of energy. Sixty-one percent of this was derived from coal, 31 percent from natural gas, 3 percent from oil, and 5 percent from nuclear.

Slide 4 shows GRU's retail electric customer accounts. We served 82,623 customers during 2002. I'm comparing two previous forecasts along with this year's forecast, and we're forecasting customer growth of about 1.8 percent a year through the planning horizon.

Slide 5 shows GRU's net energy for load last year at 2,008 gigawatt hours. Again, the forecasts from the previous two ten-year site plans here along with this year's ten-year site plan projections and we're looking at a forecast growth rate of 2.1 percent a year.

GRU's summer peak demand last year was 433 megawatts. We've experienced a mild summer so far, and this year's peak to date is only 418, though the forecast was 451. This slide compares the two previous ten-year site plans forecast with this year's. And we're looking at an average annual growth rate of about 2.2 percent a year through the planning horizon.

I'm not going to read through this list, but it summarizes GRU's involvement in demand-side management programs and activities. I just put the list before you so that you'll have it for review.

This chart shows --

CHAIRMAN JABER: Excuse me. I'm sorry. Something on that last page caught my interest. Under renewables, solar for schools?

MR. KAMHOOT: Yes. There are, I want to say -- I thought it was Department of Community Affairs. Somebody had some grants available, and we're pursuing some of that money to -- and we have at this time planned two small systems for some middle schools in our community.

CHAIRMAN JABER: Thank you.

MR. KAMHOOT: Okay. This chart shows our installed capacity, available capacity, summer peak demand, and the bars represent a peak demand plus a 15 percent reserve margin, which is what we use as a planning criteria. GRU anticipates approaching its 15 percent reserve threshold about right here, about right here, in 2011, and so this increase in the capacity line represents a proposed addition of a 75-megawatt combustion turbine that we included in this year's plan.

So, in summary, GRU expects to need additional resources to maintain its 15 percent reserve margin through 2012. At this time a 75-megawatt combustion turbine is proposed for year 2010. GRU has just begun an integrated resource planning study, and all resource alternatives will be evaluated in this process. Conclusions reached from this IRP will be included in GRU's 2004 ten-year site plan. That's all I have. If anyone has any questions, I'd be glad to try to answer them.

CHAIRMAN JABER: Is your plan suitable for ten-year site purposes?

MR. KAMHOOT: Yes, we believe it is.

CHAIRMAN JABER: Commissioners, do you have any questions?

Staff?

Thank you.

MR. KAMHOOT: You're welcome.

CHAIRMAN JABER: JEA. Go ahead.

MR. ISLEY: Good afternoon. My name is Dale Isley, and I'm the manager of the electric system planning group at JEA. And we'd just like to thank the Commission and the staff for letting us come here and make this presentation.

The first slide is representing the existing capacity resources at JEA. We have a capacity winter rating of 3,238 megawatts and in that number that excludes our firm sales and includes a 207-megawatt unit price power sale from Southern

Company.

The next slide is the winter peak forecast. And the dots that you see on the graft are the actual peaks that are occurring during the winter. The red line that you see is a normalized for that period and then the forecast going out to 2012 or 2015 time frame. And that growth is basically representing a 3.16 percent, you know, growth rate is what we're projecting.

The next slide is the net energy load that we're projecting. And again, the early years showing actuals and the out years, and that represents a 2.84 percent growth rate projection on that line.

The next slide, our reference plan showing the future plans that JEA has to meet the 15 percent design or the demand margin there. In 2005 we have the purchase of the 70 megawatts from a biomass industry, which is a green power incentive that we have. We have a planned purchase of 245 megawatts, and we utilize that through the TEA, or The Energy Authority. And then in 2005, activity is converting two of our brand new Branch CTs into a combined-cycle. And that's primarily the reason for the purchased power, is we'll be taking two of the CTs off-line to do the intertie for the combined-cycle. So it's a short-term purchase during the winter there to allow for that construction to happen, and then they come back up on-line during the summer.

Moving out to the year 2009, we have in our planning a build of a combined-cycle unit and in 2010 the CFB. And we're currently in the process of an integrated resource plan to identify site assessments for these future plants in the JEA area.

MR. HAFF: Before you leave that slide, I have a question. This fluidized bed unit has been your plan for a couple of years, and I guess that's -- I'm just curious, is that based on a least-cost expansion plan, or is it just JEA strategy to add coal to the mix?

MR. ISLEY: Just a strategy to add more coal to the mix at this point because it's so far out on the planning horizon. It was just to allow for some diversity in the fuel mix at this time.

MR. HAFF: Okay. At what point in time would you have to seek a need determination from this Commission or would you have -- we'll be seeing the filing if this were to, in fact, go forward?

MR. ISLEY: The integrated resource plan that we're currently, you know, working on right now would be in that report. We'd probably have to identify that need, you know, within the next probably six months to a year time frame because of the long time it takes for the coal unit to go through.

MR. HAFF: Okay. Thank you.

COMMISSIONER DEASON: I have a question. On the 2005 time frame there's a purchase of 70 megawatts from Biomass Industries, and you mentioned that this is partly in response to your green power incentive program. Could you briefly explain that incentive program?

MR. ISLEY: JEA has an internal strategy to involve themselves with green power, and photovoltaic is part of it. Gas recovery of landfills is part of that generation mix. And this Biomass Industries is a purchased contract to do the same with this industry. We have a purchased contract in place with this industry, and we're monitoring that progress very closely in order for them to meet that date. So that's what it's all part of.

COMMISSIONER DEASON: So what type of green power will be produced -- this 70 megawatts, what will it consist of?

MR. ISLEY: It is a process to -- of biodegradable material, basically. It's grass and trees basically is what it amounts to. That's what they're utilizing.

COMMISSIONER DEASON: And you already have a contract in place with Biomass Industries?

MR. ISLEY: Yes, sir, we do.

And, in summary, the final sheet is showing the winter peak demand versus capacity, and the blue -- the bars represent the system capacity based on our planning forecast. The first line, which is green, is the peak that we see in our system, and the upper red line is the 15 percent margin. So as you can see through the forecast years, that we're maintaining our 15 percent margin on the demand. So basically that concludes the presentation. So if any other further questions --

CHAIRMAN JABER: Commissioners, do you have questions for Mr. Isley?

Staff?

I'm assuming your plan is suitable for ten-year site purposes?

MR. ISLEY: Yes, ma'am, it is.

CHAIRMAN JABER: Thank you. Thank you for your presentation.

MR. ISLEY: Thank you.

CHAIRMAN JABER: Staff, remind me. Last year and the year before, we found I think it was just two plans that were conditionally suitable.

MR. HAFF: I believe it was two years ago we found the FMPA plan conditionally suitable, and it had to do with unspecified purchases.

CHAIRMAN JABER: Okay. OUC is next.

Why am I thinking about Kissimmee? Are you sure it was just FMPA?

MR. HAFF: Yes, ma'am.

CHAIRMAN JABER: Okay. Where's Mr. Tart? He didn't hear me. Where's Tom Tart?

MR. ROLLINS: I don't know. He's doing something; I'm not sure.

My name is my Myron Rollins; I'm with Black & Veatch here representing OUC. We did their ten-year site plan, and I've worked for them for 25 years, so I have a pretty good history with them.

We can probably skip the content slides since the guy that put it together for me went to our presentation class that said, tell the audience what you're going to tell them, but we only have eight slides, it's pretty redundant. We start out with their goals which are pretty straightforward and what a good utility ought to be doing. The probably important thing from your standpoint is the 15 percent reserve margin.

Next is their existing capacity, and probably the most important thing to note is their pretty significant amount of coal and nuclear capacity, which is fortunate in today's market situation. The Stanton plants are the coal units, along with their joint ownership in the McIntosh plant. I think it's also interesting that all their units are jointly owned.

Another significant aspect, we think, is their agreement with St. Cloud. I guess in 1997 they entered into an interlocal agreement with St. Cloud to provide all their power supply requirements for a 25-year period and take over operation of their existing diesel units and purchased power agreements. And they recently extended that for another ten years.

Next summarizes their purchase power agreements. The 15 megawatts with TECO is -- came through the St. Cloud arrangement. And then a few years ago, they had sold the Indian River steam units to Reliant, and as part of that, they took back a PPA. That PPA expires September 30th of this year but has options for another four years. And these are the -- there's current commitments on those options.

Next slide shows their load forecast. Expected growth rates are a little less than 3 percent and pretty consistent with most of the rest of the state; still pretty significant growth compared to other parts of the country.

The current unit that they have under construction is Stanton A. It is a 633-megawatt nominally rated two-on-one combined-cycle scheduled for commercial operation October 1st of this year. It's jointly owned with OUC, FMPA, KUA, and Southern-Florida. The Southern-Florida capacity is purchased back by the municipal utilities under a PPA arrangement. They're, I think, currently undergoing their performance test. It's -- Southern Company has done a very good job on that unit. It's essentially ready to run.

Next is their expansion plan. It shows Stanton A coming into service and their ownership and their purchased power portions of it, their optimization of their Reliant options. It also shows that they have some opt-out arrangements after the first five years and a portion of the PPA from Southern Company on Stanton A and shows right now the economics are to opt out of that, or to opt out at the portions that we have shown there at least. And then finally in 2011 the simple cycle combustion turbine as well as one in 2008.

And, lastly, OUC has no conservation goals required by the Commission, but they still view DSM as important. So they have six programs in place and encourage conservation of demand-side management in their system. That's all we have, if you have any questions.

CHAIRMAN JABER: Commissioners, do you have any questions of OCU?

Okay. Staff?

Thank you for being here.

MR. ROLLINS: Thank you.

CHAIRMAN JABER: City of Tallahassee.

MR. CLARK: Good afternoon, Commissioners. I'm Paul Clark, planning engineer for City of Tallahassee electric utility. I believe you-all have a copy of our presentation in front of you.

Just real quick to summarize the contents of our 2003 ten-year site plan and the activities we have undertaken since the publishing of that report. Just some general information.

703 megawatts of total existing power supply on a net summer basis, looking at a current summer season; 652 from our owned generation resources; and 51 megawatts under purchased power contracts. Although we are traditionally a summer peaking utility, our all-time peak demand for electricity occurred this last winter with the cold weather, 590 megawatts. In comparison, our summer '02 peak demand was 580 megawatts. During the calendar year 2002 sold -- I guess I should put this up here for you-all to look at -- 2,741 gigawatt hours of our energy to our retail customers.

Just real quickly, a graph of our annual energy use. I don't believe that our forecast has changed a lot between the 2002 and 2003 ten-year site plans, though maybe in some of the out years we have seen some downturn in the growth that we attribute somewhat to the reduction in incremental additions, particularly for the state agencies. As you're well aware, the state makes up quite a bit of our retail load, and with the cancellation or postponement of certain additions, the state has resulted in a slight downturn in the forward forecast both for energy and for peak demand. But, generally speaking, the 2002 and 2003 forecasts are pretty close to one another. And I believe that the information that we submitted to staff in response to their supplemental data request will bear that out.

As I mentioned, Tallahassee is a summer peaking utility historically. We plan our system to maintain a

17 percent reserve margin to accommodate any unforeseen circumstances such as extreme weather, extended generation outages. We took a look -- if you'll recall me having discussed with you in past years, the prospect of maybe increasing our reserve margin criteria up to 20 percent to be consistent with the stipulation that the IOUs and the Commission agreed to some years ago.

The IRP study that the City conducted with the assistance of Black & Veatch identified that for a system of our size and our unique graphic orientation that 17 percent sort of fell in the midpoint between a .1 loss of load probability on an assisted and unassisted basis. So we feel -- and plus it also looked to be the least-cost reserve margin criteria for us to attempt to maintain. So we're sticking by our 17 percent.

This combination bar and line chart just depicts our existing resources. I did notice one error when I showed up this morning. The last two years, 2011 and 2012, the yellow bar representing our Purdom Unit 7 -- Purdom 7 is actually scheduled to retire in the spring of 2011. It's 48 megawatts summer net generating capability. None of our planned additions are represented on this chart. I'll be discussing those a little bit later on.

One of the considerations in putting together our ten-year site plan, of course, is the forecasted price of fuel.

Like other's presentations, we do see the gas price projections dropping off after the near-term spike that we've been experiencing or enduring. And this is of paramount importance to Tallahassee, of course, because we are predominately natural gas and oil-fired.

Among the strategic considerations, one of the biggest determinants in the economics and the risks going forward for City of Tallahassee has to do with the viability of the transmission system. We have the need to back up the loss of largest unit contingency by being able to bring power in from neighboring systems across our transmission system. That effectively limits the amount of transmission that we have available to use for long-term power purchases, which I'll note again later is one of our preferred means to resource and fuel diversity since we are, as I've noted in the past and will tell you again, now limited by city ordinance, absent a citizen referendum, from building any coal on our system in Leon County or in an immediate adjacent county. We also --

CHAIRMAN JABER: How old is that ordinance?

MR. CLARK: It dates back when the City attempted a repowering of its Hopkins 2 oil and gas-fired steam unit to fluidized bed coal combustion. The citizenry were not supportive of the idea of adding a coal unit to our system I guess primarily because of concerns about the environmental impact or the air quality.

CHAIRMAN JABER: Was it the '80s, the '90s?

MR. CLARK: I think it was late '80s. It was before I came to work for the City, but, yeah, late '80s.

CHAIRMAN JABER: But for that ordinance, would you qualify, you think, for any Department of Energy clean coal technology grant?

MR. CLARK: You know, I don't recall specifically, but it may very well have been that the repowering project at Hopkins was to have taken advantage of some of those funds. I don't see any reason why but as you mentioned for that ordinance that we wouldn't be able to qualify.

We do try to also stay on top of our transmission export capability so that we may export incidental excess from our system into the wholesale power market. And both from the interests of furthering our electric system reliability and our electric system economics, we have been very closely participating and monitoring the respective RTO development activities in the Southeast. We've been very active in our preparation and actually are cosponsors of the SETrans Regional Transmission Organization and are very interested in continuing our involvement in the GridFlorida development activities once that recommences.

A lot of this material is reiterating things that I've mentioned to the Commission in the past. Transmission is of key importance to us because we do have two-thirds of our power supply basically represented by two generating units on our system; therefore, loss of any -- either one of those two units can have a tremendous impact on us both from a reliability and economics standpoint.

We have an aging fleet of combustion turbine generators. Our Hopkins GTs are over 30 years old, and the Purdom GTs are approaching 40 years old. It's for this reason that our 2003 ten-year site plan and the last two ten-year site plans have shown a preference towards new peaking facilities. Those quick-start peaking units provide us with some flexibility both from an operation standpoint but also in allowing us to diversify our overall generation mix in terms of base, intermediate, and peaking resources.

Fuel diversity is a very important issue to us. As I mentioned, we are prohibited from building a coal unit. That doesn't mean that we can't purchase some by wire. Then we run up against the transmission concern, being able to make a long-term purchase commitment and still have adequate transmission to back up that loss of largest unit contingency. Therefore, you know, we do want to continue to work on maintaining or improving our transmission situation such that we might consider purchases or other financial instruments as a means to increase fuel diversity.

We're monitoring very closely the developments at the federal level with regards to the new energy legislation.

We're becoming more and more familiar with the potential system benefits of distributed generation. Those types of units have been identified specifically in our last two ten-year site plans as being ones that bring some value to the City. We're still on the lookout for some potential alliance opportunities, possibly joint participation in a power -- a generation project either at one of the City's plant sites or some other location.

And I would point out that City of Tallahassee was one of the organizations that was -- whose plan was deemed conditionally suitable for planning purposes because of the inclusion of some unspecified purchases in our past plans. I'm happy to report to the Commission that as expected, for the summer of 2003 and summer of 2004, we have contracted for power supplies in order to cover those small needs that we had identified for those years.

The IRP study that I mentioned earlier that the City conducted with Black & Veatch did consider demand-side and conservation alternatives to power supply. In general, the potential demand and energy savings are insufficient to offset the need for new power supply. The only option that was looked at among the portfolio of demand-side options in our IRP study that was even marginally cost-effective was a direct load control program. Our previous experience with a pilot direct load control program met with limited acceptance by the citizenry, and so as a consequence, we're looking at monitoring utilities' efforts with some of the developing demand response type of programs, either a customer-initiated or a price response type of program.

CHAIRMAN JABER: I happened to catch one of your meetings on television when you all were -- your Commission was debating the fuel price issue, and I think it was in context of rates going up, perhaps. And Commissioner Lightsey made an excellent point about taking that opportunity to educate constituents on fuel mitigation and the possibility of looking at that ordinance and fuel diversity.

Could you sort of brief me on what you might do in terms of your outreach efforts on mitigation, fuel diversity, possibly dealing with that city ordinance?

MR. CLARK: Well, I don't think that that's a new development. I think that the prior Commission, more specifically former Mayor Maddox, had on a number of occasions in the past pointed out our risk by virtue of being so dependent on natural gas and oil as our primary fuel sources. We really haven't, to my knowledge, started thinking about how we might approach the public about revisiting the issue. I think it best -- we perceive it to be a very sensitive issue for our citizenry and then want to make sure that we approach it carefully.

And as previous presenters have pointed out, we still have the economic hurdle to overcome. So, you know, things like DOE subsidies would be something that we would also have to look into before we even would think about approaching the citizens about their acceptance of that type of alternative.

CHAIRMAN JABER: Thank you.

MR. CLARK: We are very much interested in the possibility of participation in a solid fuel project if it were to take place somewhere other than on our system.

As I mentioned, we did contract for purchases for summers of '03 and '04 to cover those small incremental needs and to bridge our plan to the next generation additions. We're looking at quick-start peaking generation to be in service by 2005. There we're looking at a combination of central station combustion turbines versus distributed generation located at maybe one or more of our existing substations to provide some other system benefits. Long term, based on the economics of our analysis, combined-cycle still is the preferred local generation addition, though, as I mentioned, we will be continually on the lookout for purchase opportunities for solid fuel-based resources.

Since the filing of our ten-year site plan this year, we have initiated technical feasibility and environmental impact assessments for the peaking generation units that we're contemplating for '05, looking at potential sites for distributed generation and what sort of hurdles we may be facing there. We, this summer, issued an RFP for bids on the peaking generation equipment and are expecting responses to that RFP by the end of this month or first part of next month.

In general, separate RFPs both for the short-term and the long-term needs, expecting four to six months for development and evaluation of those different proposals. We'll take the bids that we get from those RFPs and put them back through our planning models, updating our inputs, changes that have taken place since our 2002 IRP study, and take those results back to our City Commission with a proposal and solicit their approval. That concludes my prepared presentation. I'm ready to take any questions if you may have any.

CHAIRMAN JABER: Commissioners, do you have any questions?

Staff?

Thank you.

MR. CLARK: Thank you.

CHAIRMAN JABER: Unless I skipped someone, Mr. Haff, I have the last planned presentation is from Seminole.

MR. HAFF: Correct.

MR. MAHAFFEY: My name is Lane Mahaffey; I'm Seminole's director of corporate planning. I should probably introduce in advance Mr. Quang Tang in case I need him to bail me out. He's going to be handling the slides. Mr. Tang is a planning engineer with Seminole. It's a pleasure to be here to present in just a very high-level way the results of our ten-year site plan for you and answer any questions you have about it.

The first slide I would like to focus you on is the color graphic. It's called "Figure 1, Winter." What this slide does is give you a profile of Seminole's generation portfolio as it evolves over time. There's a lot of information in that slide, and I'm not going to dwell on all of it unless you have questions. You know, it tells you what generation we own, what generation we purchase, what generation we plan the reserves for versus someone else planning the reserves for. But the focal point of this slide as far as the ten-year site plan is the green area, which is the generation build out plan or backstop. That's the capacity that we have not filled yet to meet our forecast load, that green area.

And you can see that there's -- you can't see the numbers, but there's about 300 megawatts in 2007; there's a little more in 2008, '09, and then a lot more in 2010. And so that's where some of our purchased power contracts with independents and others are expiring, and so we have needs for generation that are growing in that way.

There's also a color graphic for summer I'm not going to dwell on, but it just gives you the same picture for our summer peak profile and the capacity and its associated ratings for the summer period.

Now, I'm going to play musical slides here for a moment. I'm skipping to the Tabular Figure 5 which is a tabular rendition of the generation additions that are shown in the green area on the prior graph. This is what we call -- well, the first several items, Payne Creek, you'll note in the top left-hand corner, Payne Creek GT A through E, that is our new peaking plant. It's approximately 300 megawatts in size. It's five quick-start aeroderivative style combustion turbines. They will be sited at our Hardy site along with the Hardy power station and along -- on the same side as our Payne Creek station, which both of which are already operating. We've recently selected that site.

Those generators are essentially -- though this slide needs to be updated, it shows the status as waiting to be authorized. That has been recently authorized, and we're moving ahead and are under contract. So that is a site that will be under development imminently, and the engineering is going on associated with that.

So the rest of that slide is really what we call our generation backstop plan. We will -- our normal process is we will -- as we have for at least 10 or 15 years, we will go out for competitive bids as we see generation needs coming up within our planning horizon. And our planning horizon is -- we're looking at is, like, three to seven years out depending upon which type of capacity we would be building. For peaking, it's generally in the three-year time frame. If we go to intermediate or combined-cycle, it might be in the four- to five-year time frame, and then coal would be more in the seven-year time frame. And so what we do process-wise is even though this is our backstop plan, we will make sure that we have the opportunity to build those resources at whatever time we make a decision on a purchased power contract or a decision on a build option at that time, but we will always have the build option at hand.

And so these needs we've shown you can see the modularity that we've assumed there is, for the peaking units, the module size of both peaking and combined-cycle resources in the 150- to 200-megawatt module size, but realistically, we're going to be out for competitive bids for both self-build generators and purchased power contracts. And we may, in fact, buy different module sizes than that. So that's just a backstop plan.

But the result of that plan, again, using those module sizes is shown -- results in a reserve margin profile on -- let's see, is that the next slide? It's the color -- the red and the blue line, Figure 3. And you can see that our reserve margin projected resulting from this plan yields reserve margins in the 15 to 20 percent range. The jumps -- the abrupt changes in it are really the result of the abrupt changes in purchased power contracts expiring and then us filling that with generation of a designated module size. In reality, we may end up fitting that need exactly, and there may be -- and you may not see that reserve margin percentage jumping around, but it's essentially got a floor of 15 percent, as I'll show you on the next slide.

The next slide, Figure 6 -- and I guess that's my last slide. Figure 6 is our reliability criteria that we use. Our reliability criteria has evolved over time, but we use a 15 percent minimum peak reserve margin. We also have in parallel with that, and have for a number of years, an unserved energy equivalent that's our version of the loss of load probability, but it's an internalized unserved energy criteria.

And a few years -- as our system grew, what's happened is the driver now is the 15 percent. It used to be that the -- and in prior years, we were driven by the 1 percent, and the reserve margin was whatever it took to achieve that, but now it's crossed over. And so the 1 percent is easily met and the 15 percent minimum is what drives it.

Subject to your questions, that's all I had to present to you. I would ask you, if you have any questions associated with any of that --

CHAIRMAN JABER: Commissioners, do you have any questions of Seminole Electric?

Okay. Staff?

Thank you for being here.

MR. MAHAFFEY: Thank you very much.

CHAIRMAN JABER: This is the point where I need to ask if there's anyone in the public who wishes to address the Commission during this workshop? Anyone I left off?

Mr. McWhirter, come on up.

Mr. Haff, are you aware of anyone else?

MR. HAFF: Mr. Green.

CHAIRMAN JABER: Mr. Green. Okay.

Welcome.

MR. McWHIRTER: May it please the Commission. My name is John McWhirter; I'm a consumer representative primarily for industrial consumers. For purposes of this presentation, you can call me Jeremiah McWhirter rather than John McWhirter. It's more of a biblical reference.

Consumers are always interested in the ten-year site plan because it gives our forecast for the future on two essential ingredients that govern the cost of electricity, and those two essential ingredients, of course, are supply and demand. And so what we've heard here today so far is what is electric capacity or supply in Florida today, and what is the electrical demand? And the picture we have -- you've gotten reports from the individual utilities, but the presentation made by the Florida Reliability Council consolidates the things that were in the ten-year site plans filed last April.

Now that you have this, your staff is going to work with it for the next few months and then come to you with a report as to whether or not the plans are suitable. And from a consumer's viewpoint, I think there's some things that the staff should look at, and the answer may be easy possible answers, but there are matters of concern or should be of matters of concern to consumers.

The overall projections of a 15 to 20 percent reserve margin makes it look like there's a nice relationship between supply and demand which should hold prices level. My recollection, and I've been around a few years, is that ten-year site plans have always done a pretty good rosy future picture. But what's happening currently is really the thing that's most important to the short time view of consumers. And I think what is happening currently is different than what was projected ten years ago and it's different than what is projected to happen ten years from now.

And if you look at Mr. Paul Elwing's exhibit at Page 6, it shows the cumulative capacity additions to the system, and it's composed of two parts. It shows existing capacity and then capacity additions for the next ten years. And it's a bar graph. And it looks like we have something like 39,000 megawatts of capacity during the summer peak. That's interesting.

Then if you look at Dr. Green's exhibit and you go to Page 12. And then on that Page 12, if you look, first of all, at the winter peak we'll see that in the year 2003 of this winter, the demand on the utility systems for the customers who were then operating their electrical appliances was something like 45,000 megawatts of demand. So that's considerably less demand on the system last winter than the system had available to meet that demand.

And if you go to Page 11, we come to the summer peak, and the summer peak is somewhat closer, but it still shows that in 2002 we had a summer peak demand of somewhere around 40,000 megawatts, which is about 1,000 megawatts more than the supply that was available last summer in Florida to meet the customers' requirements.

So the question that first comes to your mind is, wait a minute, where does this electricity come from? Well, your first line of defense is you have 1 million residential customers in the state of Florida who have agreed to have their electrical appliances cut off in times of the summer and winter peak. Their air-conditioners go off in the summer and their heaters go off in the winter, and so that helps bring the demand down to the supply level. And then you have about 200 industrial customers who have agreed to shutdown their plants and send their workers home in order -- if there isn't enough supply in the state to meet that demand. And those two components, the million residential customers and the 200 industrial customers, supply about 3,500 megawatts of capacity, and that 3,500 megawatts of capacity is what you have that is available when that supply is short. And currently, our supply is less than demand in the system if you look only at the utilities that reported to the Florida Reliability Council. Now, there are other electric utilities in the state, and those electric utilities aren't covered in this report. And, to some degree, I think they may be our salvation.

There's another problem that occurs to me that I would recommend to your staff for review. When you show what we have in the available supply in the state, the question is, this is a long, narrow state, and can that supply which may be located anywhere in the state get to the point where the customers are? And so you need to -- and I haven't heard anybody here today say very much about it this, but what is the status of Florida's transmission system?

Does that transmission system enable the independent power producers that are in Florida and the utilities that have capacity -- Gulf is not really connected to the rest of the state. It's way out in the peninsula, as you know. So does our transmission system tie in with the available capacity and enable that electric supply to get to the customers?

What's the status of merchant plants in Florida? Well, that's a pretty gloomy picture. We've seen that merchants or independent power producers have left the state in droves for a number of reasons. But there are three real problems with merchant plants, as I see it, that needs to be looked into by your staff. The ones that have been able to build in Florida, unless they had a firm contract with a utility, have had to build inefficient plants. They're not fuel efficient. The ones that do build and are efficient -- if they could be sufficient and if their supply meets the -- they can sell it for cheaper than a utility can produce it, there's no obligation in the state of Florida for that utility to buy that electricity. So they may be there, but there's no obligation to buy. And if you can use your own facilities and make more money because you have a fuel company that sells fuel to your electric company, there's a strong tendency to utilize your own equipment rather than buying from a merchant plant even if it's cheaper.

The major defect I think that exists in the Florida wholesale market, which is where the supply has got to come from since the investor-owned and municipal utilities don't have adequate supply, is there has to be some way for people to know what supply is available and what it costs. And we used to have in Florida what they call the broker system. And it was a good bulletin board. And at every moment in time, the broker knew what was available and what it would cost for his power. And if it was cheaper than he was producing it, he would bring it in from the broker, the cheaper system.

You don't see any broker sales anymore because we have a competitive market and we've got a competitive market in an area where the supply is short, so the price goes up. And there's no bulletin board if you wanted to buy electricity to know where that -- the cheapest electricity is. It's all done by individual telephone calls. So I would think I would recommend to your staff --

CHAIRMAN JABER: What's the OASIS system, Mr. McWhirter?

MR. McWHIRTER: -- in your monitoring of the -- yes, ma'am?

CHAIRMAN JABER: Mr. McWhirter, what's the OASIS system for then?

MR. McWHIRTER: Well, we don't have an OASIS system in Florida that I'm aware of that is a decent method for communicating the information. I think there are certain areas in the state where there's -- FMPA has a pool, I think, and others have a pool, but it's not a good statewide system. And the things that come to me -- you know, I've proven to you over and over again I'm stupid and make comments --

CHAIRMAN JABER: You said that. We've never said that.

MR. McWHIRTER: Well, I've got to admit it. I've gotten to that age in life. So there may be answers to these questions, and obviously, you didn't want us to belabor --

CHAIRMAN JABER: No. The purpose of my question is, I thought the OASIS system replaced the broker system. Am I just incorrect?

MR. McWHIRTER: Well, you may not be incorrect. The FERC came out with OASIS and that's a major component of their wholesale power market. In Florida we had the broker system that was like an OASIS. Today, the way utilities transfer power is they'll send out a request for proposal, like you heard one of the utilities talk about, and they'll send it out on e-mail, or they'll call their typical suppliers. But there's no big bulletin board like there used to be where you can say, JEA has some extra power from one of its plants, and it's willing to sell this at "X" price. And then you've got the transmission problem that you all have spent a lot of time looking into on how to get that power from point 1.

Another issue that Mr. Deason focused on I thought when the presentations were being made is, what is the age of the power plants in Florida? Since I've been around here the, last big surge of power plant building ended about 1984. So we've gone for nearly 20 years without the construction of any major power plants. Now, when those plants came on-line, they gave -- they set up a depreciation schedule to recover the costs of the plants over their useful life and that's normally 25 years. Well, our nuclear plants, the Turkey Point system, I think those were built in the late '60s. The nuclear plant for Progress Energy was built in 1976. I think St. Lucie came on about 1979. They have a 40-year license. So that's a source of inexpensive power that's coming near the end of the license periods.

Now, it may well be that those plants have been totally rebuilt, they have been relicensed, and they're okay, but I think for your staff that's certainly a legitimate line of inquiry to determine if those old plants are still viable and doing good. And, you know, some of them have been repowered and we come out better through the operation.

One of the interesting things that has resulted from independent power producers is the efficiency of plants. Older plants are not as efficient as new plants because subsequent to Section 210 of PURPA, new technology has been invented. And as you know, these old plants -- and they're different for gas and for coal, but on average, back in the '80s when they were putting these plants in, they had a heat rate of 10,000 to 12,000 Btus for every kilowatt hour that was produced. And the interesting part of that is, that means that the fossil fuel going in has a Btu energy value of around 11,000, the electric kilowatt hour coming out has a Btu value of about 3,400. Now, that is very inefficient from the fuel point of view. The new combined-cycle plants and the other advances that have been made in the system have brought that down now to in the range of 7,000 Btus of fossil fuel going into 3,400 Btus of kilowatt hours coming out. That's much better.

But as a gentleman from Progress Energy opined, and that was most interesting, he said they look at fuel prices when they're doing a new generation plan and they know that -- well, you remember what he said, but the interesting thing to me was the decision made frequently hinges upon the capital cost as opposed to the fuel cost. It may be that you have to spend more in capital costs, like a coal plant that takes longer to build, to get the benefit of lower-priced coal. And unless gas prices are going to stay up, there's a disinclination to build a coal plant. But there's another factor and that has to do with your regulatory operation.

If I'm a utility owner, and I certainly don't fault them for this because this is part of their responsibility, you look at building a power plant with a high capacity cost and buying more expensive fuel, there are two considerations that I would think that if I were a utility owner would occur to me. He said, well, I sell fuel to my power plant, so I'd like to keep doing that, and I don't want to reduce the amount of fuel I buy. And the other thing is the fuel cost is passed directly to the customers with guaranteed recovery. Whereas, if I spend money on capacity, it will be a number of years before that capacity comes on-line. It's going to affect my earnings, and I can put the capacity on with no change in rates unless my return on equity falls below a certain level. So given the decision of whether to build a new plant for -- to obtain some efficiencies and get rid of some of the old plants, the decision -- there's a strong tendency to do something that's more expensive than fuel and less expensive in capital costs.

CHAIRMAN JABER: Mr. McWhirter, just give me an idea of how much longer you've got.

MR. McWHIRTER: I would say 2 minutes and 17 seconds.

CHAIRMAN JABER: I'm going to hold you to it.

MR. McWHIRTER: Okay. I say that because I'm just about done. The transmission system I mentioned before, and I think that's a very serious problem for us because you remember during the RTO GridFlorida stuff they say they're going to now spend a billion dollars to upgrade our transmission system. So we may have some real problems. And I hope you-all have your staff look seriously at the transmission system.

So recommendations for staff inquiry is the age of the utilities that are content here, the price elasticity of DSM. I've noticed that people leave DSM when the price -- when they get too cold in the winter and too hot, and my clients leave the state. The open wholesale market, is there, in fact, transparent pricing? Should utilities be required to buy from the least source cost provider? And what is the status of merchant plants in the system, and does it have reasonable access to the utilities?

And I thank you for letting me put you to sleep this afternoon, but those are the kind of things that give consumers heartburn if you know a little bit about the business. And I appreciate you taking the time to listen to it.

CHAIRMAN JABER: Thank you for being here.

Commissioners, do you have any questions of Mr. McWhirter?

Staff?

MR. HAFF: No.

CHAIRMAN JABER: I have questions for you staff. The age of the infrastructure has come up several times, and I don't think we have traditionally included a section on that in the report, at least I don't recall. But there's nothing that would preclude us from including it in a section, maybe other?

MR. HAFF: Yeah, I was just going to comment that, you know, some of the questions I asked a few of the IOUs today had to do with a cost-effectiveness analysis of retiring older units and how that's evaluated on a year-to-year basis for planning purposes, and that, I think, sort of -- I thought it got to Mr. McWhirter's point of, you know, how long do you keep aging units on-line.

As far as operating older units, if they become inefficient, then they go further and further down the dispatch order, and they're not dispatched as often. So unless they're really needed, the older units may not run as frequently and that's sort of an operational --

CHAIRMAN JABER: Well, as a foundation do you even know the age of each unit? Is that information you readily have?

MR. HAFF: Yes. The in-service date of each of the units is in the ten-year site plan.

CHAIRMAN JABER: Okay. Commissioners, I think it would be good to have some discussion of how the retirements factor into planning purposes. And to the degree you need additional information, I would hope you just pursue that post this workshop and include whatever information you have.

MR. HAFF: How do retirements affect the planning process?

CHAIRMAN JABER: And, what, you said with regard to the cost-effectiveness of the retirements? I think that's what Commissioner Deason was asking about several times. Include that discussion.

MR. HAFF: Okay.

CHAIRMAN JABER: With regard to the transparent pricing, I could be completely wrong, but I thought that there is a mechanism in place for -- the point was people don't know what supply is available and at what price.

MR. HAFF: Yeah. There's a FLOASIS system. I know Ms. Campbell knows far more than me about FLOASIS, but it pretty much replaced the broker system for hourly pricing of what's available and what utilities need.

MR. BALLINGER: Now, Commissioners, I need to correct Mike a little bit. The FLOASIS is for transmission reservations for contract arrangements. The broker system basically faded away in lieu of -- remember, the broker system was based on a split-the-savings approach. You had cost information on both ends, the buyer and seller; the transaction price would be in the middle. That and the evolving of the competitive market, we've gone to more market-based rates where people can just negotiate rates so that fixed mechanism has gone away in preference for negotiated terms. So people are making deals over the phones. And with the confidentiality, they're not disclosing who it's with and that thing. So there's not a bulletin board for somebody to go look at, but the transactions have actually been increasing.

MR. McWHIRTER: PMJ has something --

CHAIRMAN JABER: Hang on second. As we promote and continue on with the wholesale competitive market, though, market-based transactions are exactly what you want to promote.

MR. BALLINGER: Exactly.

CHAIRMAN JABER: Okay. Mr. McWhirter.

MR. McWHIRTER: I was just going to say you've got to have a market before you can have a market-based transaction. And if people -- if the prices are confidential, nobody knows what the price is. So PMJ has a system where you -- you know, people the day before show what their price is going to be, and the utilities can all bid on that. We don't have that, I don't think.

CHAIRMAN JABER: Thank you, Mr. McWhirter.

Commissioners, any other questions of staff before we go on to Mr. Green?

Did you switch on me?

MR. GREEN: Well, Mr. Moyle figured that I can go first.

CHAIRMAN JABER: Oh, okay. Why don't we make sure we've got the last list? Mr. Moyle and then Mr. Green. That's it? Okay. Because I have to tell you, I returned my sandwich, so I have not eaten lunch.

Mr. Moyle.

MR. MOYLE: Thank you, Madam Chairman. And I'm going to be brief. You-all have had a long day and a lot of presentations and whatnot. There's one thing I just wanted to make sure was on the radar screen because I understand this proceeding to be a look at the reliability of energy in the state and to take into account a lot of different things, and you've heard a lot of them today. But it seems to me that there's a trend developing that potentially could impact reliability that I think ought to be given some consideration. And I don't have an answer to it, but I think it's appropriate to pose it as a question, which is, a lot of generation units are being proposed around the state and sited in the state in a way that consolidates the assets, and given the age that we live in, particularly if those generation facilities and clusters are a long way away from the load with a lot of transmission lines and whatnot, it seems to me an inquiry needs to be made as to whether that's the best way to assure reliabilities, to have a lot of assets in one place, or does it make sense potentially to have the assets diversified and spread out and maybe closer to load centers?

You know, when you talk about diversity of fuel supply and mix and whatnot, I think a question, at least in my mind anyway, has been raised with respect to diversity of plant locations. And I think in some instances you're seeing a lot of eggs being put into one basket. So I just wanted to make that point. And thank you.

CHAIRMAN JABER: Thank you, Mr. Moyle.

MR. GREEN: Thank you, Madam Commissioner. Commissioner, I'm Mike Green representing the independent power producers in the state. I appreciate the opportunity to make one comment and maybe offer two questions perhaps of FRCC or of staff. First comment being -- and I promise I'll be done in about three minutes. The comment being that, you know, we -- PACE really -- it's refreshing to see that Tampa Electric has voluntarily issued an RFP, if you will, for some peaking capacity, though that is not required by the new Bid Rule that's out. But they have solicited bids on some peaking capacity in '05, and Florida PACE commends TECO on that effort.

It only makes sense that, as you've heard today, if there's 14,000 or 16,000 megawatts of new capacity coming down the pike, whatever the number is, and that's going to cost anywhere between $6, $7, $8 billion to somebody that's seeking competitive bids on all that capacity, it only seems to make sense. And so we are refreshed to see Tampa Electric voluntarily taking that and broadening the scope of the existing Bid Rule.

First question perhaps for FRCC, and I guess it follows up on what John Moyle just said, and that's a reliability issue, and I guess just to expand for 30 seconds on what John said. For example, a Hines unit, they have Hines 1, 2, proposed 3, 4, 5, 6, I don't know if it goes to 7 or not, but you've got 3,000 or 4,000 megawatts that's going to be located in one 1,600-acre farm. The risk to reliability of, you know, one mishap to a transmission grid or one mishap to a fuel, you know, inflow to that site or one mishap to water can cut, you know, what, 25 or 30 percent of their total capacity off the grid? Having some diversity, geographic diversity spreading that 3,000 or 4,000 megawatts out between six, seven, or eight different sites would appear to me to have less risk to calamities. That, as John said, in this day of increased awareness to terrorism, everything else, that might be an increase in reliability and has -- the question being, has FRCC or staff really looked into the risk on reliability of centralizing generation as opposed to geographically diversifying that generation?

Second question, again, maybe for staff is -- and I think Mr. Haff mentioned just a few minutes ago cost-effectiveness of the units, and in that cost-effectiveness evaluation, is there any ongoing tracking of the costs of the units proposed in the ten-year site plans as compared to what one the RFPs that ended up in the decision to build those plants?

For example, I think in the FPL ten-year site plan Martin Unit 8 is -- if I do the math right is costing about $20 million more than what they said a few months earlier in the need determination hearing of what the Martin Unit 8 would cost. The fixed O&M costs quoted in the 2003 ten-year site plan of $9.07 I think is what they quote per kilowatt year. That compares to the $7.75 per kilowatt year quote that was used in the evaluation of alternative bids. And that 17 percent increase in fixed O&M spread out over a 25- or 30-year life of a plant is a significant amount of money when you're talking about a plant that is 1 million kilowatts. Every dollar per kilowatt hour -- or kilowatt year is a lot of dollars. And just a question to the staff: Is there any ongoing tracking of that in the cost-effectiveness comparison that Mr. Haff had talked about?

CHAIRMAN JABER: Thank you, Mr. Green.

MR. GREEN: That concludes my comments and questions.

Thank you, Ma'am.

CHAIRMAN JABER: Thank you. Mr. Ballinger, with regard to the last question first, it's my recollection from the need cases that you look at the costs exceeding projections only if there is a cost recovery case?

MR. BALLINGER: Correct, that's when we would look at the cost of the plant, at the time when they come in for cost recovery.

CHAIRMAN JABER: So that issue was never addressed in the ten-year site plan proceeding?

MR. BALLINGER: No. Now, I don't know what kind of information we get from an accounting perspective as far as what's being booked as the unit is being constructed. I don't know if there's any tracking there.

CHAIRMAN JABER: And I recall your position, which I agree with, is that that issue is only relevant to the degree the companies are trying to recover the incremental difference.

MR. BALLINGER: That's -- I mean, in essence, that's what you're looking -- is that delta between what they said in the RFP at the beginning of the need determination versus what you come in at.

CHAIRMAN JABER: With regard to the first question on geographic diversity and whether that brings less risk, I don't know if the FRCC is here, but I will give you a very brief opportunity to respond if you are. The question is, does the

FRCC consider centralized generation and the effect on reliability?

MS. CAMPBELL: I am still here. My plane is going to be at five, so I've been sticking around. Yes. The FRCC does do transmission studies, and they look at the location, whatever happens to be in all of the individual utility's planning models. They do a ten-year study, so we did look out ten years in advance. And if these projected units are in these utilities' models, that they're incorporated into an aggregate database, then it's looked at. And they'll do contingency analysis upon that to see if there are any problems looming out there. They will look at if there are actions that can be taken, and if there are not, they will bring that to the engineering committee who will then look at this and try to determine where it needs to go. So the transmission working group of the FRCC does do an analysis in the long run of transmission plans with the added generation in mind.

CHAIRMAN JABER: Commissioners, do you have any other questions?

Staff?

Thank you very much. I want to thank the participants in today's workshop.

Staff, give us a very quick plan for what you expect to do next.

MR. HAFF: Okay. We'll write the draft review and bring it to Internal Affairs. I have two potential dates, November 24th or December 1st. It will be one of those two Internal Affairs meetings, and we'll bring the final report for your review at that time.

CHAIRMAN JABER: Okay. And there are some things we asked you to follow up on, so I would just ask that you work closely with the people that participated in the workshop and vice versa.

MR. HAFF: Yes.

CHAIRMAN JABER: Thank you again for participating. This workshop is over. Thanks.

(Workshop concluded at 3:15 p.m.)

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STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

WE, LINDA BOLES, RPR, and TRICIA DeMARTE, RPR, Official Commission Reporters, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that we stenographically reported the said proceedings; that the same has been transcribed under our direct supervision; and that this transcript constitutes a true transcription of our notes of said proceedings.

WE FURTHER CERTIFY that we are not a relative, employee, attorney or counsel of any of the parties, nor are we a relative or employee of any of the parties' attorneys or counsel connected with the action, nor are we financially interested in the action.

DATED THIS 21st DAY OF AUGUST, 2003.

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