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 E. LEON JACOBS, JR. COMMISSIONER J. TERRY DEASON COMMISSIONER LILA A. JABER COMMISSIONER BRAULIO L. BAEZ COMMISSIONER MICHAEL A. PALECKI
DATE:	Monday, August 13, 2001
TIME:	Commenced at 9:30 a.m. Concluded at 2:40 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	KORETTA E. FLEMING, RPR Official FPSC Reporter

IN ATTENDANCE:

ROBERT ELIAS, FPSC Division of Legal Services.

MICHAEL HAFF, FPSC Division of Safety and Electric Reliability.

JOHN CURRIER and LINDA CAMPBELL, representing Florida Reliability Coordinating Council.

LEO GREEN and MARIO VILLAR, representing Florida Power & Light Company.

BEN CRISP, representing Florida Power Corporation.

BILL POPE and MICHAEL J. MARLER, representing Gulf Power Company.

WILLIAM A. SMOTHERMAN, representing Tampa Electric Company.

RICK CASEY, representing Florida Municipal Power Agency.

TODD KAMHOOT, representing Gainesville Regional Utilities.

CHUCK BOND, representing Jacksonville Electric Authority.

ROBERT MILLER, representing Kissimmee Utility Authority.

PAUL CLARK, representing the City of Tallahassee.

MATT BLANKNER, representing Orlando Utilities Commission.

IN ATTENDANCE: (Continued)

GARL S. ZIMMERMAN, representing Seminole Electric Cooperative, Incorporated.

P R O C E E D I N G S

CHAIRMAN JACOBS: Good morning. We want to welcome everyone to today's Commission workshop on Ten-Year Site Plans. Will counsel read the Notice?

MR. ELIAS: Notice issued by the Clerk of the Florida Public Service Commission on July 9th, 2001, advises that a workshop will be held at this time and place in the matter of the review of the Ten-Year Site Plans of Florida's electric utilities.

CHAIRMAN JACOBS: Very well. The order process today, I assume, will be that we'll just have a series of presentations by the companies, and we have some agendas, I think, that have been attached to the Notice that went out. Are there any other procedural matters, Staff, to take care of?

MR. HAFF: I'm Michael Haff from the PSC Staff. I just want to welcome everyone and note that when you come up to give your presentation to make sure that the court reporter gets a copy. We have the overhead projector over here on this other table. It'll read transparencies or hard copies of papers, whichever you prefer, and just make sure that you state your name when you start your presentation.

CHAIRMAN JACOBS: Very well. And with that, we will begin. FRCC, you'll lead off?

MS. CAMPBELL: Yes, sir.

CHAIRMAN JACOBS: Thank you. You may proceed.

MS. CAMPBELL: Good morning, everyone. I'm Linda Campbell with the FRCC. We have a presentation this morning with our load resource plan and reliability assessment study. Mr. John Currier is the chair of our resource working group, and he'll lead off the presentation. And then, we have Mr. Leo Green, who is the chair of our load forecast task force, and he will also do a presentation on the load forecast analysis. And to my right I have Mario Villar, he is representing Henry Southwick, who is the chair of our engineering committee today. Thank you.

MR. CURRIER: Good morning, Commissioners; good morning, ladies and gentlemen. I'm going to spend the first 45 minutes on the load and resource report and reliability assessment as filed here with this Commission this summer and Leo will spend approximately 30 minutes on the load forecasting section. The resource working group, as well as our forecasting team, spent a significant amount of time this year evaluating our methodologies, reviewing our forecast over time, and Leo's going to make a report on that related to the state of Florida.

Again, our report on our load resource plan and reliability assessment filed on July 1st and August 1st, respectively. I thought I'd start out with providing the Commissioners the punchline about this year's forecast, and it really boils down to four or five main points.

First of all, our load forecast is going to show a little higher demand growth here in the next ten years than you saw last year, and Leo will be able to comment on that. It's generally driven by fact that the new census information is in, and population growth for the state of Florida is expected to be higher than we saw in the previous year's forecast.

Secondly, you'll find that the firm reserve margins for the state of Florida are also higher reported this year as compared to last year. In fact, you'll find that firm reserve margins for each of the next year is approximately 20% and a little bit higher in certain years.

The third point is that most of the generation proposed by the utilities, as well as the projects that are proposed for contracting purposes, are natural gas-fired capacity, approximately 15,000 megawatts of that capacity planned over the next ten years. And the last point I want to make about the generation is the fact that overall, the forced outage rates and availability in the state of Florida's generation fleet continues to improve and it shows we have a sustained availability of approximately 90% of all of our capacity.

And the last major feature that we'll talk about in this report is the gas pipelines. There will now be two pipelines serving the generation needs of the state of Florida. We'll talk about FGT and its expansion needs, as well as

Gulfstream.

COMMISSIONER DEASON: Let me ask the question. You used the term firm reserve margin?

MR. CURRIER: That's correct.

COMMISSIONER DEASON: How do you contrast that to just the plain-old reserve margin?

MR. CURRIER: Commissioner Deason, the FRCC applies a firm standard, which is sometimes just called a reserve margin, but it's a measure of how well we serve the firm native load, both --

COMMISSIONER DEASON: You used the term firm. Is that something new or am I just supposed to interpret that as reserve margin?

MR. CURRIER: No. It's just the same standard we've used.

COMMISSIONER DEASON: Okay.

MR. CURRIER: Okay. From a demand perspective with our summer and winter forecasted demand, you could see that the growth rates for summer is approximately 2.6%, winter is 2.4%, and those are somewhat higher than last year's forecast. And again, this is driven by the new census information out and the population forecast supplied to us by the Bureau of Economic and Business Research.

COMMISSIONER JABER: Let me -- on the change in the population census information, do you -- is this an incremental increase based on the number of people or do you also add the incremental increase associated with, like, the number of appliances, the number of computers that might be in the household?

MR. CURRIER: Leo, do you want to comment on that? The answer's yes.

MR. GREEN: Yes.

COMMISSIONER JABER: Good answer.

MR. CURRIER: Apparently, we're missing a mike here.

CHAIRMAN JACOBS: In your explanation, you also indicated that some of the increment had to do with a new telecommunications load. I assume that had to do with the concentrated Teleco hotels? And I seem to have observed recently in the press that much of that is not going to be realized. Many of those sites are, indeed, not going to ultimately take on the kind of load that was anticipated. Is that your indication as well? And if so, would these projections still hold up?

MR. CURRIER: Go ahead, Leo.

MR. GREEN: That's correct, Commissioner. We are not seeing the projected amount of telecom load. The facilities have been built; however, the tenants are coming in slower than what's projected. So, the net -- if I had to do this over again, the net would be half of what we're saying than what we think this plan - and for this year, to give an example, it was

181 megawatts. I would go with about 80 megawatts this year.

COMMISSIONER JABER: Associated just with the telecommunications?

MR. GREEN: Just the telecom. There is a possibility, however, if this economy picks up that that could accelerate again.

CHAIRMAN JACOBS: Because the facilities are already there?

MR. GREEN: The facilities are built.

CHAIRMAN JACOBS: I understand. Thank you.

MR. GREEN: Yes.

COMMISSIONER JABER: But I want go back to my question with respect to the incremental increase on appliances and computers in the household. How is it you take that into account? What do you use to figure out how many computers are in a household or what the incremental increase in appliances will be?

MR. GREEN: Every so many years there are surveys done. It gives you an idea of the growth in different types of appliances. These are fed into those models that use end-use information and that is captured. There are other models that you can -- electric models will also capture that effect because of the increased usage that is seen, but there are surveys that account for the increases in not only computers and fax and Internet access and printers at home and people working at home, all of that is captured, yes.

COMMISSIONER JABER: And those surveys are done by the utilities?

MR. GREEN: They're done by the utilities, and FRCC coordinates one, I think, every four years.

COMMISSIONER JABER: Thank you.

MR. CURRIER: The last point I want to make on this particular diagram is the fact that the summer and winter peak demands continue to parallel each other through time. I think, last year we saw a little bit of convergence towards the end, but it continues now to show a parallel theme.

Comparing last year's forecast to this year's forecast, you can see that there is additional demand forecasted in the market and it's approximately about 900 megawatts in that last year difference, so that puts us up around 43 to 44,000 megawatts of firm demand in the summer. And the same trend is true for the winter, which is approximately 1,300 megawatts of additional demand forecasted in the outer year of 2009 through 10.

On the capacity side, the utility site plans have indicated a total of 15,400 megawatts of additional capacity over the ten-year period. And you can see year by year the change in that capacity. Most years are typically 1,500 to 2,000 megawatts. There are a couple of years, such as '04 and '08, where there is small amounts and, of course, as you go through time, the timing of these power plants will be adjusted accordingly as load and other things change.

COMMISSIONER DEASON: Let me ask the question. I see that the existing column that stays fairly constant, I assume from that that you're anticipating retirements of existing facilities?

MR. CURRIER: The -- that's correct. That's correct, Commissioner. Some of the repowering projects, for example, which use existing assets, are reflected in these numbers where the capacity that's existing today stays in the blue shade and the new incremental repower is in the pink shade or the new additions.

I also want to point out that a significant amount of this capacity is natural gas-fired. There are just a few smaller projects in the state that are either oil or some coal machines; for example, Lakeland submitted their McIntosh 4 proposal for a fluidized bed project. I'm sure they'll be ready to comment on that later today.

The capacity mix for the state of Florida increases from 43,000 total megawatts in '01 to 55,000 by 2010. And you can see the mix as it changes through time. The coal and nuclear mix tends to go down as an overall percent and gas, obviously, is going up 30% to 46%.

COMMISSIONER JABER: You have nuclear going down. How is it you -- how was it you arrive at the projections related to fuel mix? Everything I've read leads me to believe that the reliance on nuclear may actually increase. Am I just wrong on that?

MR. CURRIER: All right. Let me go to that slide next for the fuel mix. This is the fuel mix based on energy output, based on resources. And again, Commissioner Jaber, the nuclear number actually is declining and, I believe, the reason for that is the nuclear units are putting out maximum output today, so as you go through time just their percent tends to go down as the energy growth continues to go up. You're approximately 200,000 gigawatt hours of net energy for load. That's actual output of the power plants in 2001 and it grows approximately 250,000 by 2010.

COMMISSIONER JABER: What's "Other"?

MR. CURRIER: Other, in this case, is energy coming in from Georgia, mostly, the firm imports and other imports coming across the border as well as some nonfirm energy that is being bought by other power plants in the state, primarily merchant type capacity.

COMMISSIONER DEASON: Why is it going down? I know it's -- you have a bigger base in 2010. You know, the increase there is some 20%, but you're having your "Other" from 10% of the total applied to 5%. Why is that?

SPEAKER: Commissioner Deason, if I may -- Mario Villar from Florida Power & Light -- the southern purchases that FP&L has phase out in 2010, that's a big component of that 10% number in 2001. That's probably the main reason why that number goes down.

COMMISSIONER DEASON: Okay. This is just a contract that is phasing down? Is that what that is?

MR. VILLAR: The southern purchases expire in 2010. It's 931 megawatts at this point.

COMMISSIONER DEASON: Okay. Let me ask this question: What fits into the category of non-utility generation?

MR. CURRIER: Nonutility generators would be qualifying facilities, some of the waste treatment type of facilities, as well as a contracted merchant for this report.

COMMISSIONER DEASON: And you're anticipating that -- why is that almost being cut in half over this ten-year period?

MR. CURRIER: Many of the QF contracts expire during this period of time and that's generally driving most of that change. And then, what we have reported are contracts that we -- that are in place today or at the time of the publication of this report which, to my knowledge, there's two major QF -- excuse me, merchant type contracts. Both are with Seminole today, one is with Constellation, and the other is with Calpine, and those are included in these numbers. So, as we go through time and more merchant capacity is contracted, those numbers will change.

COMMISSIONER DEASON: So, while you can't predict, because you don't really have anything in hand, in reality you expect that when we actually reach 2010 there's probably going to be a larger percentage of nonutility generation?

MR. CURRIER: There's a good chance for that, sir, yes. It depends, again, on how the market develops here in Florida.

COMMISSIONER DEASON: Okay.

MR. CURRIER: The next page is our firm import transfer capability from the southern system into Florida, and these numbers are like last year, they haven't changed. There is a decline in firm imports that's expected next year compared to this year and that's due to FPL has a decrease in its contracted capa-- or needs, as well as Tallahassee.

CHAIRMAN JACOBS: Do you expect that would be picked up by anyone?

MR. CURRIER: The import transfer capability will pick up on the far right column, column 5, so I expect that the market is certainly looking for transmission capacity coming out of Georgia. I would expect that it would be picked up.

CHAIRMAN JACOBS: I have only heard mention of it, but on several occasions heard, I think, it's that EPRI and others have some research under way which looks to take existing inter-tie kind of technology and improve on it so that it will expand capacity of existing facilities. Is that something that you're aware of? And if so, would it have any kind of impact on how input capability?

MR. CURRIER: To my knowledge, sir, we haven't -- the FRCC hasn't conducted that type of study. We could take that on as an issue for the next year and take a look at that.

CHAIRMAN JACOBS: If you would, inquire. I think that would be useful to inquire into that.

MR. CURRIER: Okay, we will.

COMMISSIONER DEASON: I see that you're projecting that the import transfer capability, column 2, is going to remain fixed at 3,600. And I'm sure it's speculative at this point, but have you all given any thought of the possibility of a southeastern RTO and whether that would have any impact on the transfer capability into the state?

MR. CURRIER: We have not at the FRCC. I'm not sure if the folks involved in GridFlorida have done any of that type of work.

COMMISSIONER DEASON: Well, it's extremely premature at this point, but I guess you have to utilize the best information you have. I just was -- if you had any thoughts as to whether that would be a possibility at this point.

MR. CURRIER: I've only approached the transmission transfer capability as a physical limitation, and I'm not sure if an RTO would necessarily change these numbers, but we can also check on that.

COMMISSIONER DEASON: Well, I guess -- I know it's a physical limitation. I guess, my thoughts are if there is a southeastern RTO and if it's a for-profit entity and they're looking to make investments to maximize their revenue, would you anticipate that a good source of maximizing revenue would be to increase the import capability into the market in Florida?

MR. CURRIER: Certainly, a for-profit RTO would look at those options, yes.

COMMISSIONER DEASON: Okay, thank you.

MR. CURRIER: Our next slide is the dispatchable resources, DSM resources through time, and generally those are staying consistently at the same levels, both in interruptible levels as well as load and management through time, approximately 2,800 megawatts.

I'm going to switch into the FRCC reliability assessment for this year and speak on our reserve margin reviews, analysis of the availability and forced outage rates, a small discussion on load forecasts, and then talk about the natural gas transmission.

The FRCC, as a region, has a 15% adequacy standard for firm reserve margins. As the Commission knows, last year the utilities came forward with a voluntary 20% standard and you'll see that reflected in these numbers.

This particular slide may be out of sequence, but I tend to put all the reserve slides together here, but as you look at this, both summer and winter reserves throughout the study period are 20% or above, the highest being the winter out in '07 and 2010 time frame, but these are fairly level reserve margins, again, all above 20%, or 20 or a little higher, and certainly above the 15% FRCC region. Comparing 2000 to 2001's summer reserve margins, all years except for 2003 are higher in reserve margin in this year's forecast, and this is particularly evident in the out years.

COMMISSIONER DEASON: Why the change in 2003 or the reduction in the forecast?

MR. CURRIER: I think, Commissioner Deason, partly it's the load forecast is higher and it could be also, and subject to check, some of the timing on the units may have come in in '02 or they may have been delayed in '04, for example.

COMMISSIONER JABER: I know we went over this last year, too, but remind me what goes into -- for the FRCC purposes, what goes into the reserve margin calculation? It's only the investor-owned utilities estimates?

MR. CURRIER: These particular numbers are all the utilities in the FRCC region.

COMMISSIONER JABER: Okay, including Southern Com-- which utilities are in the FRCC region?

MR. CURRIER: Linda, do you want to comment on those?

MS. CAMPBELL: Well, let me go to a page here, and I can share with you the utilities that are part of the report. Let me get to the right page. The entities that have been included in this report would be the Florida Keys Electric Cooperative, Florida Municipal Power Agency, Florida Power Corporation, Florida Power & Light, Fort Pierce Utilities, Gainesville Regional Utilities, City of Homestead, Jacksonville Electric, Utility Board of Key West, Kissimmee Utility, City of Lakeland, City of Lake Worth, New Smyrna Beach, Ocala Electric, Orlando's Utility Commission, Reedy Creek, Seminole Electric Cooperative, City of St. Cloud, City of Tallahassee, Tampa Electric Company, and City of Vero beach. Their information has been included in this aggregate report.

COMMISSIONER JABER: Okay. So, it's peninsular Florida, munis and co-ops and not southern, right?

MS. CAMPBELL: That's correct.

CHAIRMAN JACOBS: You have some data in here at the back though for the whole state. That has some of Southern in it, that has Gulf information in it as well, right?

MS. CAMPBELL: That's correct. There is a state supplement also in the load and resource plan that would account for Gulf and Alabama Electric co-op.

MR. CURRIER: And to the extent Southern is selling firm capacity into Florida, that is included in our reserve margin calculations.

COMMISSIONER JABER: Okay. Thank you.

CHAIRMAN JACOBS: Kind of building on the question, in 2003, I think, the data here would indicate that while the 2001 plan shows a somewhat slightly lower reserve margin it still is at 22% for the 2001 plan; that's correct, right? Which is compared to 2002, which is at 20%, so that's an increase over 2002.

MR. CURRIER: That's correct, by one percent point, that's correct.

On the winter reserves, we have actually three years where we're slightly below last year's forecast, that's in '02, '03 winter through '04, '05, and then it picks up in the out years again. And again, that would be due to timing of machines, as well as the load forecast change but, again, you know, those are 23, 24% levels, certainly above the 20% by the IOUs and certainly above 15% for the peninsula.

CHAIRMAN JACOBS: Now, this one -- probably it would be interesting to find out what in 2004 -- winter 2004, 2005 here we're seeing not only a reduction from last year's plan, but also a reduction overall in reserve margins. Do you know what particularly is contributing to that?

MR. CURRIER: This particular year, as I mentioned a few minutes ago, in '04 there's less capacity added on the system than a couple of the previous years. For example, let me find the right slide. Here we go. If you go from '03 to '04, you can fairly see an uptick; in fact, it's somewhere around 200 megawatts of additional capacity. And with natural load growth of 1,000 megawatts a year, that's what's tending to drive us down a little bit from year to year, comparing last year's forecast to this year's.

CHAIRMAN JACOBS: Looking over in the plan itself, and I'm on Page 21, and I see that there's several plants that have been retired here and one is being -- in 2003 is the first year, looks like several plants have been retired here.

MR. CURRIER: I'm sorry, Commissioner, which page?

CHAIRMAN JACOBS: Page 21.

MR. CURRIER: 21. Okay.

CHAIRMAN JACOBS: And I'm looking at, first of all, section for year 2003. And when I look at the status of the plants that -- and I assume when the capacity is in parenthesis, that means it's being taken off the system, correct?

MR. CURRIER: That's correct.

CHAIRMAN JACOBS: So, then, if you look down the status column, you see a number of those plants have been retired?

MR. CURRIER: Yes, the Hookers Point unit will be retired in '03, that's correct, as well as some of the Gannon capacity is repowered into Bayside.

CHAIRMAN JACOBS: Okay. What would be the analysis to look at those retirements and determine whether or not it would be useful to push them out a year? It doesn't appear that it would be necessary here because here, even with those retirements, we're looking at 23% in one year and 22% in the next year.

MR. CURRIER: Right.

CHAIRMAN JACOBS: But I assume that, if necessary, we could look at those retirements and make a determination whether or not to push them out a year or not.

MR. CURRIER: That's true. In the case for Hookers Point, those machines are 50 to 60 years of age, very inefficient, and they have really come to the end of their useful life for many reasons so, you know, Tampa Electric opted to retire the units and replace it in kind with the repowered Bayside project, megawatt to megawatt, for example.

CHAIRMAN JACOBS: Right.

MR. CURRIER: So...

CHAIRMAN JACOBS: And I would also assume that by 2003, 2004, you begin to see some of the nonutility generation apparent here as well. Here's my concern. If I look at this chart, it would strike me that if we came up with a harsh winter here and we're dropping units, and we have reserve margins that are going down, sounds like we need to take a look at that and make sure that if things -- make sure that things are in order as we plan before we take these plants off-line; would you agree?

MR. CURRIER: Yes, that's true. That's certainly what the utilities would all do --

CHAIRMAN JACOBS: Okay.

MR. CURRIER: -- as good, prudent practices in that area. With a reserve margin at 23, 24% and arguably as high as it's been probably in about eight to nine years, it's probably the right time to consider some of these retirements.

CHAIRMAN JACOBS: Okay. Very well, thank you.

MR. CURRIER: Continuing in the reliability assessment, what I'm going to provide the Commission is a comparison of forced outage rates between the utilities in the '98, '99, and 2000 planning studies and then compare the trends and availability between these three studies.

Forced outage rate generally is -- it's effectively just that, a situation where a unit was forced out; it wasn't planned for, it wasn't expected to go out, but for various reasons certain things break in the machines and it takes the unit down. And as we've continued to add more natural gas-fired machines in the mix through time have continued to add more megawatts on the system, you can see the general trend for forced outage rates continue to go down.

In fact, now we're getting into the ranges of 3 1/2 to 4% in the most recent study. That's a weighted average forced outage rate of all machines in the FRCC region, so this particular reliability measure continues to improve.

COMMISSIONER DEASON: Let me ask you a question. The trend here is good, and it certainly is beneficial for the system and for the customers, but at some point you can no longer continue to make improvements, even though -- I mean, at some point there are going to be forced outages. You can never get to zero. I see it's starting to flatten out starting in around 2004, 2005. Is that kind of the best anticipated rate or do you anticipate that with maybe the technological events missed or something that that forced outage rate can be even lower than 3.6?

MR. CURRIER: I think, it can continue to go down some, Commissioner Deason, as more new gas-fired machines continue to come into the system, but there is a physical limitation and some limit out there. I think, we're getting close to that at 3.6 and, certainly, you know, many of the base load machines will continue to be in this study horizon, such as our coal and nuclear units, for example.

COMMISSIONER DEASON: Well, that was my next question. Is nuclear figured into forced outage rates or is that a separate category?

MR. CURRIER: It's my understanding that is included in this number here.

COMMISSIONER DEASON: All right. Okay.

MR. CURRIER: And this particular busier slide shows the availability trends with the red line being -- the assessment was done in '98, the green line was in '99, and the blue line is the more recent one. And you can see that the blue and the green lines are fairly consistent year to year, and this is the overall availability of megawatts in the state of Florida throughout a given year, and it's hovering around a 90% level. Again, the general trend is tweaking upward as you go through time, and that's due to the fact that there's more efficient new technology continuing to be added in the mix.

I'd like to switch gears and speak about the pipeline expansions in Florida. Last year I reported on one pipeline, that's the FGT system. This year the state is benefitting from the fact we have a second pipeline to provide the fuel into the state to drive our energy needs. First point is the FGT system. FGT has just completed their Phase IV expansion, which generally is the line that runs down to Fort Myers into Lee County. It came in service in May of this year, and they are working through the permitting and contracting phases for Phase V.

Phase V is expected to come in two parts, actually. Some of it will be available next summer in '02, and the last increment of that Phase V will be in '03. There is an expected Phase VI that will come in in the summer of 2003.

This particular diagram shows the total capability of the FGT system as it's gone through its phases and its anticipated phases in '02 and '03. Phase IV brought in approximately 200 or -- yeah, 200 MCF per day of capability. That puts us on this particular blue dot right here. And then, Phase V will take us up another 425,000, which will put us in here close to that top end.

The FGT system is a 4,700-mile pipeline running from extreme south Texas all the way to Miami. And it has direct interconnections to many pipes, injection points as well as, you know, 40 interconnections throughout the system. It also has access to Canadian gas and, you know, gas wells throughout the Texas, Louisiana, Alabama basins.

The Gulfstream pipeline is a fully-permitted pipe, it is under construction, and it's coming from Alabama down, also from Port Manatee and Manatee County out. And I'm of the understanding that they're building the pipe from both ends and ultimately will connect up somewhere out in the middle of the Gulf.

The Gulfstream pipe will also have access to gas basins throughout the Gulf of Mexico, and currently there are 22 TCF of known reserves out in the gulf and, of course, there could be more as some of that expiration continues to migrate further offshore and possibly into some of the Florida area over time.

The Gulfstream is going to have 1.2 billion BTUs per day of capability, which is equivalent to a Phase III FGT system when it comes on-line. And, of course, the pipe will expand as needed. The distance of the pipe is about 450 miles from Alabama to Port Manatee, and another 170 miles coming across Florida and terminating in Palm Beach County.

I have a diagram that shows -- it's not in your package -- that kind of gives a sense of where it's going to transverse the gulf, where it's coming in, and then two major laterals, one going up into Polk County and another there in Indian -- well, down there around Lake Okeechobee, and then ultimately terminating in West Palm.

COMMISSIONER DEASON: Let me ask the question: On the capacity of the Gulfstream system, you mentioned there's 1.2 billion BTUs per day; is that going to be the initial capacity once it's constructed or is that the anticipated capacity over time, over some period of time?

MR. CURRIER: That's the initial capacity.

COMMISSIONER DEASON: Okay, that's the initial capacity?

MR. CURRIER: Yes.

COMMISSIONER DEASON: Does the Gulfstream pipeline, does it -- is it capable of being expanded? I know that FGT routinely can make expansions through looping and adding compression facilities. An undersea pipeline, can it avail itself of those type things or do they expand capacity after they actually just lay a new pipe?

MR. CURRIER: My understanding, Commissioner Deason, is it's a 36-inch pipe across the gulf, and as soon as it reaches Port Manatee, it'll go to a 30-inch pipe. And actually, a couple of those laterals are small diameter sizes so, I think, physically if you can -- once it gets to Florida's peninsula, you can add capacity at that point, either through larger pipe or a second pipe, but I'm not sure physically how much 36-inch can deliver once you consider all the packing and compression that's done to deliver gas into Florida.

COMMISSIONER DEASON: 36 -- that's -- FGT has three different lines. The 36-inch, is that the largest FGT has in place or --

MR. CURRIER: They do have that size, yes. I don't know if it's all three of their pipes are that large coming in.

COMMISSIONER DEASON: Okay, thank you.

MR. CURRIER: Mm-hmm.

This year, like last year, we followed the same reporting criteria for merchant plant capacity, and it basically works out in the report such as any uncommitted merchant plant is not listed in the report unless it is an existing plant or ground has been broken.

The case for an existing plant would be the Indian River plant which is has a few megawatts that are uncommitted. If a merchant has a firm contract with an FRCC utility but has not broken ground, the amount of the contract is shown in the interchange section of the plan, and the amount of this contract is included in the reserve margin calculation.

And again, there's -- Seminole has two contracts, one with Calpine and one with Constellation that shows in the report. And then, capacity from a merchant plant that is not under firm contract with a utility is not included in the reserve calculation; so, again, the reliability council feels that the reserve margin, at this point, should continue to be a firm reserve margin based on a truly contract or existing capacity by the utilities.

COMMISSIONER DEASON: So, that's where the term firm comes from, you're trying to distinguish --

MR. CURRIER: That's correct, that's correct.

COMMISSIONER DEASON: Okay.

COMMISSIONER PALECKI: And why is that? Why is the capacity that is not under firm contract not being considered? The plant is there, it is available, if needed; is it not?

MR. CURRIER: The reason for that is the plant, if it's not under contract, could sell its capacity out of state, it could sell it in other ways that are not considered firm for reserve purposes for calculating the true needs for the loads of the customers in that particular system.

In summary, the FRCC reliability assessment indicates that planning reserve margins have increased compared to the 2000 plan, the forced outage rates for the overall fleet continue to improve, the generating unit availability continues at the same level, which is approximately 90%, and tends to go up a little bit as you go through time. The accuracy of the FRCC's load forecast has remained high, and Leo will speak on that behalf in a couple minutes here, as we've done some comparisons over the last ten years, as well as comparing our load forecast against other regions in the country. And then, finally, the natural gas supply and pipeline expansion is expected to be adequate.

And in conclusion, the results of the review indicate the peninsular Florida electric system is reliable for the next ten years from a planning perspective. Is there any additional questions before Leo?

COMMISSIONER JABER: I've got one. Back on the fuel mix pie chart.

MR. CURRIER: Yes.

COMMISSIONER JABER: The actual plan -- does the pie chart tie to Page 42 of the plan? Is that where the estimates come from? I'm looking at Page 42 of the resource plan.

MR. CURRIER: Yes, that's the energy mix.

COMMISSIONER JABER: Okay, then, do you see under "Other" there are some fluctuations in the percentages, they increase in some years, decrease in others, but 2010 compared to 2000, I see an increase. How do I reconcile that with the comparison 2001 to 2010? I guess --

MR. CURRIER: Okay, yeah.

COMMISSIONER JABER: The fluctuations, I'm not able to reconcile with the actual chart.

MR. CURRIER: The other category is a combination of Line 1 and Line 18.

COMMISSIONER JABER: Mm-hmm.

MR. CURRIER: So you've got, for example, 2001 at 6 1/2% and 3.6%, and that gives us about 10%. And as you go through time out to 2010, you see the firm imports, as Mario indicated, as going down 2.44, and then the other is 3.3, so that's a little over 5%.

COMMISSIONER JABER: What is the explanation, then, in the -- there's a substantial increase between actual 2000 and projected -- I'm assuming that was a projected number for 2001.

MR. CURRIER: The 1.4% to the 3.6?

COMMISSIONER JABER: Mm-hmm.

MR. CURRIER: Commissioner, in all fairness, this other line on the bottom is a -- is adding all the utilities' expected generation by resource. And when you get to the very bottom line, to get to the full 100% needs, you have a little bit of an adder there called other, just to make sure it all works out.

COMMISSIONER JABER: Okay. So, it doesn't -- is what you're saying that it doesn't necessarily tie with the other that's on the pie chart picture you've got?

MR. CURRIER: It is part of that other number in there, but it tends to be more of a corrective number to make sure you get to 100% on this line than in the top line, which is the actual firm imports.

COMMISSIONER JABER: Okay.

MR. HAFF: Commissioners, Mr. Floyd has just passed out to you on this two-sided sheet, one size proposed merchant plants as of today, and this is a -- we got it from the DEP, a list of all the merchant plant companies who have applied for air permits. We have an idea, at least, of what's out there. They're listed here. The shaded ones on this page are the ones that are proposing combined cycles and, of course, if -- failure to build a combined cycle to be exempt from the Power Plant Siting Act, the steam portion of these units would be less than 75 megawatts.

And to put this in perspective, on the back of this sheet would be the potential impact of these merchant plants, if they were all to come on-line and to be available at the time of summer peak on the FRCC reserve margin and that column 4 there would indicate just a -- I guess, a scenario if they were -- these merchant plants were to all be built and be on-line at the time of peak and to give you an idea of the cumulative capacity in column 3, what we know of as of today is over 7,700 megawatts of merchant plants.

Chairman Jacobs, I think, you had some questions earlier about concerns over the winter reserve margins and the timing of retirement units and, I guess, our belief is that if, you know, some of these units on the other side of this page are actually under construction, that's a lot of capacity.

The export capability of the interchange, I understand, is about 1,900 megawatts so, I guess, it would not be physically possible for all of this capacity to be going out of state if we were to need it at a time of peak in Florida. So, the assumption, I guess, would be that most of this would be available, if we need it, assuming it gets built.

MR. CURRIER: Okay. I'd like to introduce my colleague, Leo Green from FPL, and he'll speak about our load forecast this year.

MR. GREEN: Good morning, Commissioners. In the last few years -- I'm sorry, thank you -- the load forecast is an integral part of the calculation of reserve margin, and we wanted to make sure that the numbers that are being used are the best numbers available so that the assessment of reliability in the state of Florida would be correct.

Furthermore, there have been some questions that have been bottled up to the FRCC regarding the accuracy of the forecast, and so we thought it was time enough for us to present something on the accuracy of the load forecast in the state of Florida. The issues that I'm going to cover are these, the reasons why we did it, we looked at all of the utilities, then I'd like to give you some kind of a historical insight, what were the findings of this forecast and a subtle but very important topic which is total peak versus firm peak.

Why did we do it? I guess, the basic question for my presentation today is, is the forecast suitable for reliability assessment purposes? Also, there is a lot of movement going on on the level of NERC, and NERC has included in their planning standards a charge saying that the regions must provide as accurate a forecast as accurate as possible.

So, what we did at the level of the FRCC was we reviewed 12 electric utilities in the state of Florida, and that's represented approximately 98%, 98 1/2% of the total load, and the issues that we considered when evaluating each one of these utilities was what was their historical accuracy? How could we compare across utilities the input assumptions, the assumptions make sense across utilities and across history? How good were the models that were being used? And here, we're not only talking about software, we're also talking about how well were they structurally put together, what were the factors that were considered? We looked at the outputs, how good were the outputs compared to the past? And then, we did some sanity checks, and the sanity checks that we considered were load factor, use per customer, and prior forecast.

Instead of presenting the results of each one of the utilities, we're going to do that at the FRCC level, but I'd like to advance the following regarding each one of the utilities. We did not determine or we did not detect a bias that there is no consistent over our underforecasting in any of the utilities that were reviewed.

The assumptions were homogenous across utilities. For example, we would be concerned if a given region was saying that population would grow by X percent and another region was saying that the population would grow by some significant different amount. Well, that did not happen, because we all are using basically the same sources.

For example, for population, we're all using the Bureau of Economic and Business Research out of the University of Florida, which has been proven to be perhaps the best source of that data in the state of Florida. The economic assumptions are almost all coming from Data Resources Incorporated or WEFA, which have recently joined into one company, so we have consistency of assumptions going there.

State-of-the-art forecast and methodologies. Once upon a time, only a few of the utilities could afford to purchase these sophisticated models. With the new technologies that have been produced there are a lot of models that can be found or that are very accurate in forecasting load.

The forecasts that we found were consistent with historical trends and the sanity checks checked out, and what's most important to us is that there is a self-correcting process that's embedded in the forecasting methodologies; that is, as we learn something new these are incorporated into subsequent forecasts.

Before I get into what those -- before I quantify how good those forecasts is, I'd like to create a picture of what the last ten years were. The decade of the '90s was associated with extraordinary economic performance. No one was projecting that the gross domestic product, either of the state of Florida or of the nation, would be what it turned out to be.

And each subsequent year, they underestimated the performance of the economy. The spirit was also characterized by having low price of fuels and, consequently, low price of electricity. It was hotter than normal, both on the cooling degree side, which is associated with net energy for load, and it was hotter than normal on that maximum peak day temperature; we did not see too many cold winters, and we saw somewhat of a low growth in customers, but then it grew substantially at the latter part of the decade.

It just so happens that for around the last three or four years of that decade, Florida created more jobs than any other state in the union. Consequently, we had a lot of people moving to Florida in the last few years, not retirees necessarily, but people looking for a job.

In fact, if you look at the projections from the University of Florida, they underestimated that cohort that goes around 20 to 50 years and they overestimated the retiree population. One of the reasons for that being that Florida is not as affordable as it used to be as a retiree haven. In fact, in south Florida the price of housing has doubled in the last ten years.

What this would suggest to me is that we had a period of robust economic growth, robust growth also in load. What will make a forecast not suitable for reliability purposes? If a forecast -- if FRCC forecast consistently overforecasted or consistently underforecasted, then we would say it's not suitable for reliability purposes.

Also, if this divergence tended to increase over time, we would say this forecast is not suitable for reliability purposes. Well, FRCC forecast, over the last five years, we have experienced some years of overforecasting, some years of underforecasting, and we're going to see why in a short period.

And the divergence is getting smaller over time, meaning to say the forecasts are becoming more accurate each subsequent year. What I have here is the last five years of forecast. Now, let me explain what these numbers are. In my industry, this is called a load forecast fund. The first column is actual, what was the peak that we observed in the state of Florida?

The next column that's labeled 1995, that was the forecast that was provided in the 1995 plan and 1996 and so forth up to the plan 2000. But once again, the first column is what actually happened. Below, we have a forecast error, and the size might be misleading, but if you see a negative, what the negative means to say is that the forecast was higher than actual.

When you see a positive, it means to say that actual was higher than forecast, so what we have there on the bottom section is positives and negatives. One year stands out; that is 1998, which was the hottest that we have on record and you would not expect the utilities to have forecasted that load. If you look at the actuals, if you look at the actual summer peak from 19 -- let's say, 1995 all the way down, it grew, like, 5, 6, 700 megawatts per year, except in 1998, it grew at over 4,000 megawatts in just one year to give you an indication of how hot it was in 1998.

No attempt was made here to normalize these numbers for weather. What you see is the forecast errors as they occurred. So, if you look at the latter years, the forecast, the bottom right-hand corner, we have had some positives and some negatives, and we have -- if you take, for example, '98, '99, and 2000, that first set of numbers, the forecast error is becoming smaller. I'm talking about these numbers here goes from 4.1 to 1.9 to 1.4. The forecast error is getting smaller each year and the sign alternates between positive and negative, meaning to say that there is no tendencies to overforecast or underforecast. That's one year out. If you wanted to look at two years out we'd come to this number, 4.1, down to 2.3, down to a negative .9. Once again, the forecast error is becoming smaller.

And as I said, these numbers are actuals, they're not weather normalized. If you weather normalize them, the picture will look even better. With the case of the winter peaks, what you are going to see is a lot of negatives, and what those negatives are representing is that we have overforecasted the winter peak every year with the exception of 1995, 1996, which was a somewhat cold winter.

However, the winter peaks are usually variable, and we have not experienced those cold snaps but, however, we do plan for them. At NERC level on July of this year, the planning committee asked the load forecast and task force to present an evaluation as to how the forecast was happening because of reliability problems that were being identified across the nation.

If I take out just the one year ahead forecast, one year ahead forecast, how did we do in FRCC or peninsular Florida? The blue line is the forecast one year out, the red line is the actuals. We, out of six years, out of the last six years, we have overforecasted with the exception of 1998 and 1999 where that peak temperature was hotter than normal;

however, we haven't made any attempt to normalize these, but the point is that we have over and underforecast.

COMMISSIONER JABER: Let me try to understand the -- your point with respect to the weather normalization.

MR. GREEN: Right.

COMMISSIONER JABER: If between 1998 to 2000 the weather was hotter than normal and, therefore, there was an underforecast, how do we ensure that does not occur from the year 2001 to the years, you know, 2020? Is there a normalization process that is taken into account in the resource plan?

MR. GREEN: Yes, there is. On a short-term basis, there's going to be departures from the forecast, and these are due to abnormally hot temperatures and unusual economic conditions, short-term trends, a departure from trend. That temperature -- for example, I'll speak of FPL's system, in this case.

In August of '98 and '99, we hit 94 degrees. The long-term normal temperature is 92 degrees. So, when we project, we say it's going to be 92 degrees, because it's the most likely value that will occur. We do provide high bands as scenarios, but our most likely projection is that it's going to be 92 degrees. So, if I were to take that 1998 value and adjust it downward because of abnormally hot temperatures, both of them would be in line, so there would not have been any overforecasting or underforecasting in the prior years.

This is the report or this was extracted from the report that was presented to NERC. This is how the rest of the United States has been doing, and we're included in there, so we have helped to make this better than what it would have been had we not presented these numbers.

The nation as a whole, since 1996, has consistently underforecasted actuals and that underforecast has been increasing over time. This is not the case of Florida. In the forecast findings, moving out to the outputs, how well were our outputs, I'm going to speak some of winter peak, summer peak, and we're going to compare it to history, the 2000 plan, and this year plan.

This year plan, as John said before, is higher than history and it's higher than the 2000 load plan, load and resource plan. This is what was shown before by John. That 1998 in history sticks out because of unnormality in the weather, but everything else is on trend, and the winter portion, it seems like we're above trend, but the reason is that we are considering more heavily those years when we did have a winter peak.

So, if you go off of the higher points of the history, then you can see the trend on the winter peak, because even though we have not experienced cold winters in the last few years, we still plan for them. Let me go back to this table for a second. To the very bottom there is a table that has some very important points that I'd like to make.

In history, last ten years we have grown at a rate of 962 megawatts per year on a compound annual average. Last year, our forecast was 957 megawatts. This year we're saying that our annual growth is going to be 1,052 megawatts per year, and where I'd like to call attention to is that column to the right which is the percent or the compound annual growth rate.

In history, 962 megawatts represents 3.2%. However, 1,052 megawatts in the forecast represents 2.4%. A lot of what has come across the desk of FRCC in the last year has been that type of information saying how is it possible that in the past we're growing at the rate of 3.2% and you're projecting a growth rate of 2.4%? All it has to do is the size of the base. What's important is the column before which is the absolute growth, so we're projecting good growth.

And as John said before, there's a combination of two things that are indicating this growth is we're projecting higher population growth than last year, and we have some telecom load included in this forecast. The intention of that was to clarify that point, and there is another point that is subtle, but I'd like to clarify it also, which is the concept of serve peak versus firm peak.

Let's imagine that the region has -- just for example purposes -- has the capacity of 2,000 megawatts of load control, but on that peak day the region decides to use only 500 megawatts of load control. The recorded peak is going to be 1,500 megawatts higher than what the firm forecast was. So even though we had been 100% accurate, there's going to be a load forecast error of 1,500 megawatts, because what we forecast is firm peak. The point that has to be made there is that before a forecast error can be mentioned or can be offered, the necessary adjustments have to be made, like what we have done here.

In summary --

COMMISSIONER DEASON: Before you get to your summary, let me ask the question.

MR. GREEN: Yes, sir.

COMMISSIONER DEASON: Back to your example of the 2,000 megawatts of load control but only 500 being exercised, and it would indicate a 1,500 higher peak than what was forecast, I understand the mechanics there and how that works. Do you ever go back and adjust the peaks to indicate what the firm peak was at that time, as if all load control had been exercised, and compare that to your forecast?

MR. GREEN: All the information is in the plant, except for the very first year, because we file -- the utilities have to provide this data to FRCC in January, and sometimes we don't have the information for the first year. So, right now we have included here January of 2001, but that number is not firm yet. It's not because we do not know exactly how much load control is exercised on that day.

COMMISSIONER DEASON: Okay, but it's something you're going to be looking at?

MR. GREEN: Yes, sir.

COMMISSIONER DEASON: Okay.

MR. GREEN: Based on what has been said here, the group at FRCC feels that the forecast is reasonable and realistic. We capture all the trends and new initiatives. What we detected when making these forecasts is at the end of each year there's an examination that goes on within each utility where something that could have happened that was not foreseen would be built in to the new forecast. New initiatives are things like telecom load or a new facility or a new industry coming on-line, we will make line-item adjustments to the forecast to include that. So, there is an adjustment process that occurs each year which reduces the possibility for risk, which is the second section -- the third point.

The fourth point is that what we have detected is yes, there are going to be some forecast errors, but these forecast errors can be traced directly to unusual economic conditions and extreme weather conditions. The forecasts are self-correcting. There is a consistent pattern between historical and long-term growth, if you look at the, for example, use per customer, which I did not present here. Use per customer is showing an increase in rate. We have that also in the forecast. Load factors in history is almost exactly like load factors in the forecast. We, then, concluded that the forecast that FRCC has produced was suitable for reliability assessments. If there are any questions --

COMMISSIONER JABER: I have a question, but it's back on reserve margin.

MR. CURRIER: Okay.

COMMISSIONER JABER: And again, I just want to make sure I'm understanding the numbers. Without taking load management and interruptible into account, is it correct that for 2001 reserve margin is 12%; is that correct?

MR. CURRIER: That's --

COMMISSIONER JABER: I'm looking at S-10.

MR. CURRIER: Okay.

COMMISSIONER JABER: Yeah, S-10, it says, "State of Florida 2001 Load and Resource Plan." It's based on your form 10?

MR. CURRIER: Correct. And in the year 2001, if you do not include the effects of load management interruptibles, it's 12%.

COMMISSIONER JABER: Okay. So 9%, then, for this year is contributed to conservation efforts and interruptible load.

MR. CURRIER: Yeah, load curtailable programs, correct.

COMMISSIONER JABER: Okay. All right. So, then, for the next three years, at least for winter it's longer than that. For the next four years we'll be below the 15% threshold, if we don't take into account the load management and interruptible load.

MR. CURRIER: Right. That particular margin is more of a capacity margin number, and that's correct. In the winter, there's more DSM resources that's a component of the overall reserve margin. And the reason for that is your load management programs tend to pick up more loads, such as strip heating and other things.

COMMISSIONER JABER: There is -- there have been concerns with respect to problems associated with interruptible customer contracts, so this tells me that perhaps discontinuing the offering of interruptible load might present a problem with respect to capacity as it relates to reserve margin.

MR. CURRIER: From a total number of interruptions viewpoint? Well, if you use a -- if you go to the winter and assume that you've got a 15% firm reserve number, for example, and let's take 2001 and 2, for example, which now indicates 20%. If you substitute in 15 for that, which is the region standard, that 8% number would be down closer to 3%. And obviously, the lower that goes, the more chance for an interruption situation, but as it's tending to go back up, the amount of -- the potential for interruptions tend to go down through time.

And, in fact, rarely are there actual interruptions of the interruptible class. And over the last couple of years, Tampa Electric's had a few more, I know FPC's had a few more, than what's traditionally been the case, but now we're starting to show reserves, they're coming back in closer to what we saw in the mid '90s throughout the state. And in those years there were very few interruptions, if any, for our interruptible customers.

COMMISSIONER JABER: Okay, just to use as an example, the year 2001, you established that 9% of that reserve margin is with load management and interruptible. Do you know what percentages comes from load management and what percent of that 9% comes from interruptible?

MR. CURRIER: Yes. Let me see if I can find the exact page in here. If not, in my presentation I show a diagram.

MR. HAFF: It's on Page 6.

MR. CURRIER: Also, on this particular diagram, you can see the interruptibles is approximately 750 megawatts throughout the state and approximately 2,000 megawatts are curtailable load management programs so, percentagewise, you're looking at about 70% of the overall DSM is coming from load management and 30% from interruptibles.

COMMISSIONER JABER: Thank you.

COMMISSIONER PALECKI: Now, I'm confused. When we look at S-10 and we see increasing load management and interruptible, how does it square with the chart you just put on the screen that shows no increase over the next ten years?

MR. CURRIER: Okay, on S-10, let's take the column 8 which is going from 12 to 15, okay? What you see is generally the level of total load management. Interruptibles are staying constant through time, and that percentage between column 8 and 11 should be consistent, if not -- you know, as you go year to year.

For example, let's take 2001. You're going 12 to 21. That's a 9% differential, but if you go down to 2004, you're going from 14 to 22, so that's actually an 8% differential, so what that's indicating is your DSM percentage is coming down on an overall quality of reserve calculation.

COMMISSIONER PALECKI: With the increasing population in the state of Florida, why don't you or why is there not a projection of greater dispatchable DSM?

MR. CURRIER: Each of the utilities have submitted their dispatchable resources as filed with the Commission in the goal-setting process and, in this particular year, the 1999 set of five-year goals and five-year projections beyond that. So these are, to my knowledge, the approved load curtailable levels of conservation activities.

COMMISSIONER PALECKI: Okay.

MR. CURRIER: Any other questions? Thank you very much.

CHAIRMAN JACOBS: Thank you. Why don't we take a ten-minute break. We'll come back at 11:15 for further presentations.

(Recess taken.)

CHAIRMAN JACOBS: Okay. Taking our seats again, then we'll begin again. I think, there was one question, one brief question, for FRCC, so they may not want to vacate the premesis yet. If you want to just come forward and ask your question of FRCC.

MR. MOYLE: I think -- I'm John Moyle from the Moyle Flanigan law firm. I appreciate the chance to ask a question or two. I know in years past, this opportunity has been provided and appreciate, Mr. Chairman, for allowing me to ask just a couple of questions.

There was some discussion about retirement of plants and the Hookers Point plant what, I think, you mentioned was 50 years old. In your analysis, what do ya'll consider as the average useful life of a power plant in Florida's fleet or do you consider it?

MR. CURRIER: I think, you have to go case by case. I do not know of an average type study for a power plant.

MR. MOYLE: Okay. And do you all know what the average age currently of the Florida fleet is, if you take all the plants and average when they were put in the ground, what the average age is?

MR. CURRIER: I do not know that number, no.

MR. MOYLE: Okay. And then, I guess, with respect to retirement projections, do you all make an independent analysis of retirement projections or do you rely on the utilities for those numbers?

MR. CURRIER: In the case for our case, which is Hookers Point, a small 200-megawatt. We have done internal studies on the plant, and it's been expected to retire in 2003 for at least five to six site plans now, and it's based on what we expect will be the useful life of that project. Also, it made good timing to retire at that point and time, because we have currently a Big Bend sale that goes to Seminole. It's almost one-for-one the same size in megawatts that will be coming back into our reserves.

MR. MOYLE: Okay, but I'm asking more generically speaking, in terms of you don't independently sort of figure out when power plants are going to be retired, do you?

MR. VILLAR: That's not an FRCC function, John.

MR. MOYLE: Okay. And then, the final question where there's talk about these QF contracts, you saw that figure go from 10% to 5%, you said some of that was merchant in QF. Those QF contracts, when they expire, I guess, the contracts expire, but the facilities are still there, you just don't rely on them; is that right?

MR. CURRIER: That's correct.

MR. MOYLE: Okay. Thank you, I appreciate the opportunity.

CHAIRMAN JACOBS: One brief question. With the projection of nonutility generation that may come on-line, what's being done to look at transmission requirements for that generation? Is that something that you look at or is there some independent role taking care of that?

MR. CURRIER: In this -- in the load and resource report you have a list of transmission projects, and those are submitted by the utilities.

CHAIRMAN JACOBS: And they anticipate the -- only the projections by FRCC members or does it include all projections?

MR. CURRIER: I'm not familiar, sir, with exactly how the transmission people site those projects.

CHAIRMAN JACOBS: Okay.

MR. VILLAR: Mr. Chairman, while I'm not a transmission planner, the process breaks down into two pieces; basically, what is called a generator interconnection study, which is the ability of the generator to tie to the grid without designating who they're going to be selling to, and that has minimal requirements. And I say minimal in the loose sense.

Then, there's a transmission service request which is separately made, and there's a separate queue for that in the transmission side. Generally, a generator will not -- a merchant generator, if you will, will not get into the transmission service queue, unless it knows that it's going to be selling to someone in particular. At that point, they are looking for specific transmission service to a specified load, and it gets more expensive at that point or perhaps it could, depending on who they're selling to.

CHAIRMAN JACOBS: Okay. Thank you. Next presenter.

MR. HAFF: Yes. Our first presenter for the individual utilities will be Florida Power & Light.

MR. VILLAR: Good morning, Mr. Chairman, Commissioners, ladies and gentlemen. I'm Mario Villar, Manager of Resource Planning for Florida Power & Light, and I'm going to make a much briefer presentation than the one made by FRCC this morning. I'd like to take you through the highlights of the changes in our 2001 Ten-Year Site Plan versus last year. And I'll be covering the topics of generating resource additions and what those resource additions do to FPL's fossil load probability and reserve margin standards, which form the basis for our planning criteria.

What we have in this year's plan is a significant increase from the plan that we had submitted in 2000, and you see in terms of the resource additions, we're adding approximately 6,300 megawatts in the summer by 2010 versus a 1999 projection of generating capacity additions of about 3,300 megawatts and in last year's plan approximately 4,500 megawatts of generating resources being added.

The basic changes are delineated in the bottom part of that graph, changes to mainly our Fort Myers and Sanford repowering -- repowering of our Sanford and Fort Myers facilities for about 2,000 megawatts and about 5,500 megawatts of new units. There's also a decrease in existing purchases, some of which we discussed earlier this morning, 931 megawatts that are being phased out in 2010 from the Southern Companies and some QF purchases, et cetera, that are expiring within the time frame of this study.

That one is very difficult to see, but it basically takes you through the incremental capacity additions for each one of the years from now until 2010, and for the next couple of years, as I mentioned before, the major drivers to new generating capacity additions are the Sanford and Fort Myers repowering. We also have some new purchases that we have entered into recently starting in 2001 and going through about 2005 through 2007. They actually go longer than is shown here on the base of actual signed contracts.

MR. HAFF: They are actual signed contracts?

MR. VILLAR: We do have signed contracts now, Mike, yes.

MR. HAFF: Okay. Are you going to explain that later on in here?

MR. VILLAR: I can go through that, if you want.

MR. HAFF: Yes. One of the points I was going to bring up when you were finished but, I guess, now is a good time is the unspecified purchases that were in FPL's Ten-Year Site Plan, we were under the understanding that since the plan was filed some of these uncommitted or unspecified purchases had been firmed up through contracts, and if not --

MR. VILLAR: I can put up a slide at the end, if you wish, showing what those are or I can dig it up now, whichever way you want. At the time that we filed the plan, we were still in the process of negotiating, so did not want to disclose.

MR. HAFF: We'll wait until the end, then, if you have a slide.

MR. VILLAR: Okay. As you see, those purchases were projected to -- the new purchases that Mike was just referring to were projected to phase out in 2005. There's a slight change from that based on the actual signed contracts, but then in 2005, 2006, we have the addition of Martin combined cycles Units 5 and 6, the addition of a new combined cycle unit at our Midway site, and conversion of combustion turbines to combined cycles of both Martin and Fort Myers site, followed by unsited combined cycles from there on out from 2007 to 2010. And the big change in the southern purchases in 2010 being 931 megawatts; the balance from 931 to 975, I think, is a QF purchase that expires on that date.

COMMISSIONER DEASON: Excuse me. What is the negative 975 megawatts showing in the year 2005?

MR. VILLAR: The negative 975 in 2005, Commissioner Deason, was the forecasted expiration of those purchases that Mike and I were discussing a few minutes ago. The actual number under contract is slightly different, and I'll cover that in a later slide, so it's a reduction in capacity in the plan, because of purchases expired at that time. They will actually not expire at that time, only a portion of the megawatts will.

COMMISSIONER DEASON: Under this plan, when do you anticipate that you'll be issuing an RFP to have new capacity added to your system?

MR. VILLAR: Well, you anticipated what I was going to cover at the end of the presentation.

COMMISSIONER DEASON: That's fine. You can do it in that order is fine.

MR. VILLAR: Okay. As part of our Ten-Year Site Plan, we continue to have a commitment to conservation and the demand-side management measures. These figures shown in this slide represent our goals from the 1999 Commission workshop where the goals were established for Florida Power & Light, and they are included in the plan.

You see, there's an increase from about 200 megawatts in 2001 to close to 800 megawatts by 2009. And FPL, historically, has exceeded their DSM goals. I think, for the last plan set that we had, we exceeded by about roughly 20% at the end of the period.

COMMISSIONER PALECKI: Now, the FRCC showed no increase in DSM for peninsular Florida. Does that mean that other utilities are going to have less DSM or how does this fit in with what we saw earlier today?

MR. VILLAR: I think, some utilities are reducing the -- their dependence on DSM as a reserve resource or their generation mix, if you will -- not the generation mix, but their mix of resources. Some of them are trying to put more iron in the ground as opposed to just relying so much on DSM.

COMMISSIONER PALECKI: Thank you.

MR. VILLAR: But it all depends on their individual goals. I am not familiar with what their conservation goals were.

COMMISSIONER DEASON: But the goals that you have here include more than just load management, correct? This is all of your conservation efforts that has an impact upon demand; does it not?

MR. VILLAR: Probably, Steve Sim or Leo -- I think, it includes them both.

MR. HAFF: Yes. Commissioner Palecki, what we saw earlier from the FRCC was strictly the dispatchable DSM, the load management and interruptible. Those numbers did not, to my knowledge, include any of the true conservation measures that would have been included in FPL's numbers.

COMMISSIONER DEASON: Thank you.

MR. VILLAR: What I want to just show you very briefly now is what the impact of those resource additions are on FPL's reliability criteria, which is loss of load probability and reserve margin. For FPL, we consider both of these standards to be equally important. The LOLP criteria is one day in ten years, and reserve margin FPL has traditionally used a 15% reserve margin number for both summer and winter, and we agreed at the -- in 1999 to change that number to 20% by the summer of 2004.

The graph represents the loss of load probability numbers for FPL. If you can see, they're well below the standard of one day in ten years or .1 in a year, and that they have been quite below that level for quite some time now. As a result, the reserve margins have been the ones that have been dictating our capacity additions over the last few years. The reserve margin numbers you see there, for both winter and summer, include the DSM goals that we have projected for FPL and the resource additions shown in the prior point. We're well in excess of the 15% number that FPL uses now and even the

20% number that we have adopted on a voluntary basis beginning in summer 2004.

In summary, we would expect the FPL system to be very reliable, both from a loss of load probability and a reserve margin basis with numbers that are significantly better than the standards that we abide by. And with that, what I'd like to do is cover the purchases that there was a question on, and then I'll go off to discuss the RFP that Commissioner Deason was asking about.

These were the purchases projected in our Ten-Year Site Plan. And as you see, Commissioner Deason, they did not extend through the summer of 2005. That's the reason why there was a reduction of 975 megawatts in 2005, because those resources are being taken out of the mix at that point. The actual signed contracts are the ones shown on the right. And as you can see, they're higher than the ones that we had predicted at the time the Ten-Year Site Plan was filed and they do extend for a couple years beyond 2005. Those are not reflected in any of our numbers, and they would increase the reserve margins for FPL during those time periods.

CHAIRMAN JACOBS: Could you hold that for a minute? I was trying to see your winter purchases go down and, I assume, you felt you had more flexibility in the winter?

MR. VILLAR: Generally, the peaks in the winter are of extremely short duration and we do have, in addition to our traditional reserve margin measures, we do have a number of operational measures that are available to operators, which amount to quite a few megawatts in the state that we could avail ourselves of if we needed to.

CHAIRMAN JACOBS: All right. Thank you.

COMMISSIONER DEASON: Well, explain to me -- would you put that back up?

MR. VILLAR: Sure.

COMMISSIONER DEASON: These additions are -- well, can you explain to me what they are? Are they in terms of contract purchases or are you talking about installing new capacity in the ground that you would own?

MR. VILLAR: These are purchases, Commissioner. Let me just show you the specifics as to where they come from so that it makes it a lot easier.

COMMISSIONER DEASON: Okay.

MR. VILLAR: I don't know if you can see it very well. Let me try it a little wider here. It makes it even worse, but first row up there is a 50-megawatt purchase from Florida Power Corporation going from 2001 through 2004, and this shows the summer numbers only, by the way.

COMMISSIONER DEASON: Contractually, you have a different arrangement between summer and winter?

MR. VILLAR: The number of megawatts varies from one year to the next. I don't have the details in front of me right now, but some contracts expire; for example, they might last through the winter, but they might not go into the summer in one particular year.

COMMISSIONER DEASON: Okay.

MR. VILLAR: Okay. The second row is a purchase from Dynegy, which is actually coming from outside the state, as I understand it. The third one is from Oleander Com--

COMMISSIONER DEASON: Excuse me, excuse me.

MR. VILLAR: Go ahead, I'm sorry.

COMMISSIONER DEASON: There's adequate capacity on transmission to import that energy?

MR. VILLAR: To my knowledge, there's transmission reservation to bring it into the state. Right now there is -- I believe, there's something close to a thousand megawatts of input capability into the state that is not firmed up at this point. I may be off on the number, but the third and the fourth purchases there are from Oleander, and they vary in amount, depending on when they get the combustion turbines in place.

The fifth one is from Progress Energy ventures, a new project they have in Desoto County. The sixth one is from Reliant, and the seventh project is from AES Lake Worth, which is a -- I believe, that's a repowering combined cycle unit in Lake Worth.

COMMISSIONER JABER: These contracts were finalized after you submitted your Ten-Year Site Plan?

MR. VILLAR: That is correct. I believe, the last one was signed maybe about a week ago, ten days ago, perhaps.

COMMISSIONER JABER: Okay. So these, the numbers, the megawatts, then, are not included into what you said was available capacity, correct?

MR. VILLAR: The ones that were included were the 975 megawatts that I discussed before. These are -- amount to more than the 975 that were already included in the plans. They tend to raise our reserve margin.

COMMISSIONER JABER: Exactly. That was my point. So, Staff should include these numbers as their total available capacity, which also has the result of increasing the reserve margin percentages for these respective years, correct?

MR. VILLAR: Well, if they wanted to do that, I guess, they could. I don't know what purpose it would serve, at this point, to be rerunning reserve margin calculations, but --

COMMISSIONER JABER: But this is the accurate picture as of today, correct?

MR. VILLAR: It is, but also, you know, we change the plan on a regular basis, Commissioner Jaber, and, you know, load forecasts change and all things change. I don't think it would be very productive to be fitting new resource additions with perhaps an old forecast. As of the time we filed the plan, everything was accurate. Now, we do have some additional resources, and then when we do have a new load forecast, the load forecast will be different, so...

COMMISSIONER JABER: Well, but if I wanted to know what the reserve margin as of today was --

MR. VILLAR: On a forecasted basis for FPL, that would be the firm purchases for FPL, yes, you would include those.

MR. HAFF: Can I get a copy of this sheet for summer and for winter?

MR. VILLAR: Sure.

MR. HAFF: Do you have this for winter as well?

MR. VILLAR: If I don't have it, I can get it for you, Mike.

MR. HAFF: Okay.

COMMISSIONER DEASON: And the cost of this, you will seek recovery through cost recovery clause?

MR. VILLAR: I would assume, Commissioner. I'm not in that area, but I would assume that would be the case.

COMMISSIONER JABER: Are there other contracts pending that you haven't signed?

MR. VILLAR: No, I believe, those are all the contracts at this point.

COMMISSIONER JABER: Let me ask you a question about the network access points. Last year, when we asked about the total megawatts associated with, I think, at the time we knew about one network access point, your answer -- someone's answer from FP&L was about 570 megawatts associated with the network access point. A year into this now, I think, both of them have been implemented. What are the associated megawatts with the two network access points? And then, how are you affected by a possible third one in Jacksonville?

MR. VILLAR: I think, Leo would probably be better to answer that than I would.

MR. GREEN: Yes, Commissioner. Last year we mentioned 570 megawatts. The way it works out was for this year was 180 megawatts, then next year 330 megawatts, and we peak at 570 megawatts. That was customers that have approached us requesting that amount of capacity.

Since then, the telecom stocks have taken a beating, and we have not seen the type of activity that we thought last year would be happening. This year, based on what we have seen so far, we estimate that instead of 180 megawatts this year it would be somewhere between 54 and 80 megawatts.

COMMISSIONER JABER: How many?

MR. GREEN: 54 and 80. And instead of peaking at 570 megawatts, it will probably peak at about 250 megawatts.

COMMISSIONER JABER: And that's -- Leo, that includes both NAPs, the NAP of the Americas and the BellSouth NAP?

MR. GREEN: That's correct, both of them.

COMMISSIONER JABER: And that would include whatever -- and I'm not sure that there is a domino effect, but that would include also whatever the increased demand is on the technology sector around south Florida?

MR. GREEN: Surrounding, and also includes the net effect; for example, one of the sites is what used to be the Omni Hotel.

COMMISSIONER JABER: Omni Hotel?

MR. GREEN: Okay. So, instead of having the Omni Hotel load now, we have telecom load, so we have a net effect there of losing one and adding some, so that would be the net effect of that occurring.

COMMISSIONER JABER: And how do you capture those estimates? How is it you know what the demand will be associated with the effect of the now?

MR. GREEN: The way it works is we have several departments involved. We have the customer service department that's talking directly with the customer. The first access through FPL is through customer service. Then, what we do is we don't take their estimates on a face value, because it's a tremendous amount of load, so we visit sites, like in Cleveland and Chicago, California, and then we bring in the distribution planners, and they arrive with a final estimate of how much this load is going to be, and then that's passed down to me, and then I make a line-item adjustment to the forecast, adding it on to whatever was predicted.

COMMISSIONER JABER: Okay. There was an announcement just a couple of weeks ago about the possibility of having a NAP in Jacksonville. Are you all affected by that at all?

MR. GREEN: No.

COMMISSIONER JABER: Okay.

COMMISSIONER DEASON: Didn't we -- as a Commission, didn't we approve a tariff filing awhile back concerning the -- basically, a reservation charge or guaranteed revenue or something for getting capacity? Are you familiar with that? You're not?

MR. GREEN: No, I'm not, I'm sorry.

COMMISSIONER DEASON: Okay. I think that part of the reason for that was to try get a better assessment exactly what the loads were going to be as opposed to folks just coming in saying I'm going to need, you know, X megawatts on a certain date. And once the tariff was put into effect, it's my understanding anyway, that some of those estimates have become a little more realistic.

MR. GREEN: Right. It's a very difficult issue, because it changes on a daily basis. On a daily basis we have new people coming in and new people leaving; some making deposits, some not doing it. Those that didn't make the deposit will show up three months later and say, yes, I want it. So, it's a day-to-day issue that will change constantly.

MR. HAFF: Mario, I just had one area I wanted to ask you about. You know, we've heard about voltage control or voltage reduction as an operational tool to, I guess, when we're in a tight reserve situation, you know, we can implement voltage reduction as a tool to free up more megawatts during emergencies. Are you familiar with voltage reduction tests, how that would be done, how a utility would perform one of those? And if so, could you explain that?

MR. VILLAR: I don't have any details on how it's actually performed, Mike, but we did perform a test in July of this year for our FPL system only, and we saw a reduction of about 130 megawatts, somewhere in that range. If we were to test it during the winter, I would assume that we would get a much higher reduction, because you have a lot more resisted load like heating and things of that nature.

MR. HAFF: Could you briefly explain how that test would be done, what FPL would do to perform that test? I mean, do you lower the frequency or something?

MR. VILLAR: I'm not familiar with the technicalities to how it's done. Our operational people do it.

MR. HAFF: I guess, the concern that we have, some of us on the Staff, is that you know, if you have some long feeder off of a substation the voltage is probably at or near the requirement in the Florida Administrative Code for service, you know, plus or minus 2 1/2% or whatever it is, and if you do one of these tests the voltage in that line would drop even lower, and I didn't know if you all had any experience with that.

MR. VILLAR: I don't know any particular experience, but from what I recall, I thought the standards were plus and minus 5% and the voltage reduction that we do is 2 1/2%.

MR. HAFF: Okay.

MR. VILLAR: Generally, if you have a very long feeder with voltage type problems, you might have voltage support capacitors and stuff like that holding up the voltage and the feeders, so you might be okay with that. But you're going to the point where my law school just blew out my engineering already, so I don't recall how that's done.

MR. HAFF: Okay, thank you. Are there any questions for Florida Power & Light?

MR. VILLAR: I want to cover for Commissioner Deason the RFP issue.

MR. HAFF: I'm sorry. Okay. We'll do that first, then we'll hear from Mr. Moyle.

MR. VILLAR: Yes. Florida Power & Light today placed an ad in "The Wall Street Journal" for a request for proposal for capacity and energy. We also filed it with the Commission. I understand it's already been filed today, so you should have a copy in your files. What we're basically looking at is a two-part proposal; one, to meet our capacity needs for 2005 and 2006 and that is to get to our 20% reserve margin for those years. For 2005, that requires 1,150 megawatts for 2006 is another 600 megawatts for a total of 1,750 megawatts. We are looking for bids anywhere from three to ten years, for firm capacity and energy, and also to the extent the bidder might be interested, we're also taking turnkey bids; in other words, somebody putting in a power plant in to build it for us and turn it over to FPL control after the plant is built.

The RFP is based on the units are included in our Ten-Year Site Plan for those particular years, 2005, 2006 additions; that is, Martin number 5, Martin number 6, the Midway combined cycle units, and the two combustion turbines, two combined cycle conversions that we had in the plan, both Martin and Fort Myers.

Consistent with Commission rules, we reserve the rights to match or beat any and all bids, and one other thing that we're looking at in our RFP is we're seeking expressions of interest for energy supply from new renewable resources commencing as early as 2003.

We're not committing, at this point, to enter into any contracts for these supplies, but we're trying to evaluate the availability and the cost from green power type proposals that might be interested in supplying FPL with energy from renewable resources -- new renewable resources.

COMMISSIONER JABER: Now, you said the 1,750 should take you to the 20% reserve margin. That's without including interruptible and load management or is that including interruptible and load management?

MR. VILLAR: We take into account the interruptible and load management in arriving at what our reserve margin is. Our reserve margin is above firm load, so we take out interruptible and load management out of the equation from the load side.

The schedule for the RFP, I don't know if anybody can see it, but we'd release it today. We have a pre-bid workshop for people that are interested in bidding to answer questions on August 24th. On August 31st, they would have to file a notice of intent to bid, and then the proposal will be received by FPL on September 14th. We will conduct evaluation of the proposals between September 14th and November, and at that point we would announce a short list and be in contract negotiations with any parties that might have promising proposals.

In March of 2002 is when we would expect that there would be a winner announced from this proposal, and then to the extent that a determination of need or a cost recovery filing will be required with the Commission, we expect that we would be filing that in May of 2002, and this capacity was to be in service for -- the firm capacity we were requesting by June of 2005.

COMMISSIONER DEASON: Let me ask a question on the schedule. Is this the normal amount of time that you allow between releasing the RFP and actually receiving proposals from August the 13th to September the 14th, which is 30 days?

MR. VILLAR: I don't know if there's a normal amount of time, Commissioner. We have not issued an RFP since, I believe, like, 1989.

COMMISSIONER DEASON: Okay, but you -- obviously, you believe that from today's date and the release that you're going to -- 30 days is adequate time to get meaningful proposals received? When you say proposals, I assume that that is the ultimate proposal that someone wishes to file in response to your request, and that's what you would be evaluating to come up with your short list.

MR. VILLAR: I think, it is. If you believe all the announcements with merchant capacity in the state, perhaps, a lot of those that are already announced projects would be ready to submit a proposal to us, so if you had to start from scratch, probably a month would not be enough, but I think there's enough people out there that have projects, either in the early stages or have thought about it enough that they would know enough to submit a proposal within this time frame.

COMMISSIONER DEASON: Do our rules specify the amount of time that has to be allowed between the issuance of a request and proposals being received? Staff, do you know?

MR. VILLAR: Not that I'm aware of, Commissioner.

MR. ELIAS: I don't believe so. I think, we just look at the bid process and satisfy ourselves that it's satisfactory. I don't think there's a specific time frame that's in the rule.

COMMISSIONER DEASON: And on the previous page of this handout that we just received under cost estimates, these are provided to potential participants to know, basically, what they're initially bidding against?

MR. VILLAR: On the RFP, the cost estimates are there. They're also in a Ten-Year Site Plan that has already been filed, except that the RFP rules require the information to be presented in a different format and maybe in a little bit more detail. I'm not sure exactly what the level of detail is, but the information has been out for a while already.

COMMISSIONER DEASON: And then, under your schedule again in May of 2002, there either would be a filing for a determination of need. I suppose that if you win your bid, you would need to file that to actually begin a construction of whatever you determine to be the least cost option; is that correct?

MR. VILLAR: That is correct, sir.

COMMISSIONER DEASON: Okay. But then, there's the indication there could be a cost recovery filing. That would be in the event that you would enter into a contract with someone else?

MR. VILLAR: Yeah, it could be a combination. We could enter into a contract with someone where we would jointly come in with the applicant for the determination of need for a new facility and they would be seeking the need for the facility and we would be seeking cost recovery of the contract.

COMMISSIONER DEASON: I see. And under this current state of the law you actually would -- well, as I understand it, they would need -- someone would need -- if they're not a load-serving entity, they would need the contract to come in to have status to actually request a determination of need, correct?

MR. VILLAR: For a combined cycle facility, I believe, that's the case.

COMMISSIONER DEASON: Okay. All right, thank you.

MR. HAFF: Are there any questions for Mr. Villar? Go ahead.

CHAIRMAN JACOBS: One brief question. The cost estimates here, indicating that the capacity would -- that they're bidding against is for Martin 5 and 6 -- I mean, I was just looking at your --

MR. VILLAR: It's more than Martin 5 and 6, Commissioner. There is --

CHAIRMAN JACOBS: Several others in there.

MR. VILLAR: Yeah, the cost information is for all the facilities that are included in those years, which is

Martin 5, 6, the conversion to the combined cycle, and the Midway combined cycle plant.

CHAIRMAN JACOBS: Okay. And my question -- oh, I'm sorry, it is there. Strike that.

I was just looking at what you had projected to add in Martin 5 is there, I just didn't see it when I first looked. While 6 is listed in 2006, it still would have been first quarter, so okay, I understand. Thank you.

COMMISSIONER DEASON: I have a further question. Your expression of interest in renewable resources starting in 2003, is that actually part of your RFP?

MR. VILLAR: Yes, it is.

COMMISSIONER DEASON: Okay. Is there any minimum or maximum amount of capacity specified?

MR. VILLAR: I don't recall. For the renewables, I don't think we put a minimum or maximum there.

MR. HAFF: Mr. Moyle, you had a question?

MR. MOYLE: Just a couple quick questions. I wanted to ask the same question that I had asked earlier of John with respect to the age of ya'll's fleet. Do you have an average number of the age of the plants in your fleet?

MR. VILLAR: No, I don't have it, John, but the information is in the Ten-Year Site Plan as to the commercial and service dates, so it's easily calculated by anybody by looking at the plan.

MR. MOYLE: Okay. And with respect to the bid you were just discussing with Commissioner Deason, did I hear you to indicate a preference for contracting for that capacity out of a plant that may already be under development?

MR. VILLAR: We haven't indicated any preference. We're looking at all projects that people might submit, and we'll evaluate them on the basis of how they fit into our system and the economics of the proposal.

MR. MOYLE: Okay. Maybe I misunderstood it, 30-day arrangement, I thought -- you indicated 30 days was probably a little tight for somebody to propose a Greenfield project from scratch?

MR. VILLAR: If they were just thinking of a new Greenfield project, yes, I would say it would be probably a little tight.

MR. MOYLE: Okay.

MR. VILLAR: But if they had already thought of a site and they had done some prior work on it, et cetera, it probably wouldn't be.

MR. MOYLE: Just one final question. When ya'll are receiving this information; for example, let's say like land cost of Martin which it will be compared against, do you all assign a land cost for Martin to your self-build proposal when you compare it to a proposal received from a merchant or somebody?

MR. VILLAR: I am not sure, John. That would probably be a question to be asked at the pre-bid workshop.

MR. MOYLE: Okay. I'd probably pose the same question with respect to interconnection cost just to assure it's a level playing field for everybody.

MR. VILLAR: I don't think we know interconnection cost any better than anybody else.

MR. MOYLE: Thank you.

MR. HAFF: Are there any other questions for Florida Power & Light? Okay, thank you, Mr. Villar.

MR. VILLAR: Thank you.

MR. HAFF: Next we're going to have Florida Power Corporation.

MR. CRISP: My name is Ben Crisp. I'm Director of System Resource Planning for Florida Power Corporation here to provide a summary and overview of the Florida Power Corp. Ten-Year Site Plan.

There is several key points that I want to make this morning that all roll into the considerations that were given in consolidating preparing the Ten-Year Site Plan. Those key points center around the load forecast, DSM program changes that we are working on, changes to the generation fleet, and in addition to those key points, I want to give an update on the Hines 2 project that is currently under way.

Similar to Florida Power & Light, FPC follows a current reliability criteria for 15% reserve margins. We use a similar .1 day per year loss of load probability or one day and ten years, less than one day and ten years. In the generic reserve margin docket, FPC agreed to increase its minimum reserve margin criterion to 20%. In fact, FPC will implement that minimum 20% reserve margin criterion in the winter of 2003 and '04 with the addition of the Hines 2 facility.

COMMISSIONER JABER: Mr. Crisp, what's your current reserve margin without load management and interruptible?

MR. CRISP: Without load management and interruptible? Let me get to that in a few minutes, and I've got a slide that addresses that, I believe.

COMMISSIONER JABER: Okay.

MR. CRISP: Okay? This slides depicts the seasonal peak demand forecast. On the left hand of this slide you see the actual data from 1991 through the year 2000. That shows the kind of jagged line you'll see is the winter -- actual winter peak, the smoother dotted line is the actual summer peak.

Key point here that you see is a dip in the projections that occur in 2002 and 2003. Those changes correlate to losses of contracts with Seminole, approximately 750 megawatts of contracts that will expire during 2002 and 2003. Those contracts go away. At that point, you see the impact of increased demand, which is as a result of standard growth within the system.

MR. HAFF: Mr. Crisp, this might be a good point to ask this. Typically, when a contract expires you would get an increase in capacity. The reason you're showing a decrease in demand is that these are partial requirements contracts where you supply Seminole's load that exceeds their firm capacity?

MR. CRISP: These are specific contracts with capacity amounts associated with those contracts.

MR. HAFF: Okay.

MR. CRISP: Because there is a specific amount of capacity that we are obligated to serve under that contract, when that contract goes away, so goes away that amount of capacity that is allocated.

MR. HAFF: It's seen on your system as load rather than capacity. It's seen on your system as a drop in load rather than an increase in capacity.

MR. CRISP: That's correct.

MR. HAFF: Okay.

MR. CRISP: Florida Power Corporation's load forecast process takes into account several different factors. As far as weather load relationships, we use 25 years of historical data. We compile this data and we examined the maximum peaks during that period of time. We give heavier weighting to the maximum peak periods. We gather our information from three primary weather stations within our system, which correspond to our largest load centers, St. Pete, Orlando, and Tallahassee.

We use demographic, economic, and business drivers to provide indications as to what is happening that may affect our usage per customer. We take into account those changing usage patterns with respect to either growth, as growth within the system, or as a change within -- specific changes as relates to the usage per customer. We take all of the information together on a bottom-up approach. We combine the impacts to retail, wholesale, and also the impacts from our DSM programs and combine those into the information that's necessary to drive the load forecast.

I'm going to give you a brief update on Hines Power Block 2. In January of 2001, the Florida Public Service Commission granted FPC the need request necessary to move forward with Hines 2. It's a 530-megawatt nominal combined cycle power block. Site certification was approved by the Governor and Cabinet in May of 2001. The project is currently on schedule for December of 2003 commercial operation date. With respect to the project, ground has not been broken yet, but we do anticipate ground breaking within early next year. The necessary funds that are being spent currently relate to options and completion of engineering and architect contracts.

COMMISSIONER JABER: Mr. Crisp, I don't know if you're the right person to ask or not about this issue. As you recall, when you all were coming before the Governor and

Cabinet, someone expressed a concern with respect to going forward with a project while a case -- while the case was on appeal, and I can't recall if your company clarified that the cost would be borne by -- the risk and the cost would be borne by Florida Power Corporation and not the consumer if, I guess, it's Panda wins on appeal. Do you know anything about that?

MR. CRISP: I was at that hearing, but with respect to that I think it's probably better to talk with our regulatory people to get a specific and definitive explanation of what was discussed there and our position on that.

COMMISSIONER JABER: Okay. But do you remember -- do you recall a concern expressed by the Governor and the Cabinet that to the degree there was a successful appeal by Panda that the customer should not bear the cost of the Hines 2 project going forward?

MR. CRISP: I do remember the discussion, yes.

COMMISSIONER JABER: Okay.

MR. CRISP: With respect to demand-side management resources, in the history, Florida Power Corporation has depended heavily on demand-side management as a percentage of its total reserve requirement. Over several summers, Florida Power Corporation utilized summer demand-side management programs and received significant customer complaints and customer concerns over the utilization over those demand-side management programs in the summer.

Quick to correct, there is a big difference in between summer demand-side management and winter demand-side management. Summer peaks are -- have a broad breadth during the day, they last a long time, and they stay consistent. If ambient temperatures stay hot for a number of days, then you achieve that same breadth day after day after day.

The wintertime peak for Florida Power Corporation is a very specific, very finite needle peak that happens early in the morning. And unless you get into a period of extended days of cold, that needle peak only happens one day maybe here, one day and a few weeks, one day and a few weeks. We've seen that the Florida Power Corp. winter peak for about the top eight hours of the year is equivalent to a 1,000-megawatt amount of capacity requirement.

So, from the summer standpoint, we made the decision that it was in the ratepayer's best interest to move forward with generation expansion to augment the DSM program for the summer peaks. For the winter peaks, we feel that DSM is still a very effective use of mitigating the best possible cost and reliability to the customer.

This slide shows the summer resource impact. The purple down at the bottom shows the supply-side resources as a percentage of total reserves. As you see, they're currently about 40% in the summertime. So, if our total reserves were 1,200 megawatts, then about 480 megawatts for that right now would be generation capacity, and the remainder would be demand-side management reserves. We anticipate that by 2003, 2004, to have that level of summertime supply-side reserves up to approximately 60% or roughly 700, 800 megawatts worth of generation capacity versus 3, 400 megawatts worth of demand-side management capacity.

Commissioner Jaber, does this address your question?

COMMISSIONER JABER: Yes. Thank you.

CHAIRMAN JACOBS: How do you make that differentiation? Are you doing different purchases? I think, earlier we saw that Power & Light had different purchasing schemes for summer and winter. Same principle here?

MR. CRISP: What we're doing, Chairman, is we are specifically working with our customers. We've introduced a program that was approved by the Public Service Commission where the customers, if they move or they attrit from the existing load management or demand-side management program, they're not allowed to sign back up for the summer program, so we are attritting the customers from the summer program and encouraging them to sign up for the winter-only program, and that provides considerable savings to the program, it provides a better overall package and better value to the ratepayers as a whole.

CHAIRMAN JACOBS: Okay. Thank you.

MR. CRISP: You're welcome.

As you see from the winter slide, we are approximately 20% of total supply-side reserves with respect to the total reserve margin currently. We'd like to get that into approximately the 40 to 50% amount for supply-side reserves. The reason being, it's a little bit less. We still want the DSM side to contribute to the winter reserve margin. It's very effective and very cost-effective for the customers.

COMMISSIONER JABER: A couple of agendas ago, of course, it could have been the last agenda -- the days seem to collide -- we approved a tariff for your company that would encourage self-generation for the large customers, not the industrial customers but, like, hospitals. Did that capacity, is that included in your -- that would not be included in your ten-year plan that you submitted in April, right?

MR. CRISP: I don't believe it would.

COMMISSIONER JABER: Okay.

MR. CRISP: If it happened prior to April, then it would; if it happened after April, then it would not.

This slide depicts a summary of capacity additions and changes to the system. The only significant difference in this year's Ten-Year Site Plan versus previous Ten-Year Site Plans is that we've added a peaking unit to fill in a gap that's associated with some additional load growth, and that peaking unit, 180-megawatt peaking unit will be added at DeBary Unit 11 in November 2006. The Hines energy complex units remain consistent. Those are power blocks 2, 3, 4, and 5 coming on-line in '03, '05, '07, and '09.

Although the colors don't come out very well, the yellow colors above the zero megawatt line show the additions of the combined cycle power blocks in '03, '05, '07, '09 and the DeBary peaking unit in '06. The small blue boxes beneath the line show the retirements associated with several different older peaking and steam units within the Florida Power Corp.'s system.

To summarize the overall Ten-Year Site Plan projections for reserve margins, as you see out in 2004, we achieve the 20% reserve margin, minimum reserve margin requirement. Prior to that in '03, in the summer of '03 and into '04, with the installation of Hines 2 we achieved the 20% reserve margin criteria. In summary, we project that the FPC system is very reliable over the planning horizon. And if you have any additional questions, I'll be glad to entertain them.

COMMISSIONER DEASON: I have a question. I take it that Florida Power does not anticipate issuing an RFP anytime soon.

MR. CRISP: We are in the process of completing all of the paperwork, the evaluations, and the analysis for the Hines 3 unit. The schedule for Hines 3 Power Block would be almost exactly the same as the schedule for the Hines 2 Power Block. And with that, what we're doing is we're completing all of the internal analysis on technology changes, fuel requirements, fuel balancing, optionality of the units, the internal optionality of how best to balance the needs of the fleet so that it gives the best value for the ratepayer.

Once we complete those analyses, and I project that will be within a couple of months, we will determine what the best source or the best solution for that 500-megawatt block need is. And at that point, if the solution is the Hines 3 unit or a power block, Hines 3 Power Block type, then we would issue an RFP, perhaps towards the end of the year or the early part of next year.

COMMISSIONER DEASON: So, you're looking at in relation to whether to go forward with Hines 3, you would be issuing an RFP latter part of this year or early next year?

MR. CRISP: Yes, sir.

COMMISSIONER DEASON: Okay. Apparently, in Florida Power & Light's RFP that they just announced, they have indicated an interest or an expression of interest in renewables. Has Florida Power undertaken anything in that area?

MR. CRISP: We do have a program that -- and I don't -- I'm sorry, I don't know a lot about the program itself. I know it's within our -- more of our DSM area. They are working on renewables and they are providing analyses and studies according to renewables and what we can do with renewables. I don't know what their progress is right now.

COMMISSIONER DEASON: Do you --

MR. CRISP: We have been in participation with several of the solar projects that have been funded within the state and worked with them and done whatever we could to provide additional support and interest in the solar programs in specific.

COMMISSIONER DEASON: You do not have a green power program, do you?

MR. CRISP: I would have to defer that to someone who would know if you could call that a specific green power program that's related to rates and related to being advertised as a green power program.

COMMISSIONER DEASON: Okay. Maybe if you could just provide that information to Staff and Staff could relay it to me, I'd appreciate it.

MR. CRISP: I'd be happy to do that.

COMMISSIONER DEASON: I want to congratulate you on your new logo. I just now realized that it's garnet and gold. That's --

MR. CRISP: Does that have an appeal? Thank you.

COMMISSIONER JABER: I think, it depends on who you're asking.

On the last presentation, FP&L updated the megawatts available as a result of the unspecified contracts coming to fruition.

MR. CRISP: Yes.

COMMISSIONER JABER: Do you have unspecified contracts that have actually been executed since April when you submitted your plan?

MR. CRISP: No, we don't.

COMMISSIONER JABER: Okay.

MR. HAFF: Are there any questions for Florida Power Corporation? Okay. Thank you, Mr. Crisp.

MR. CRISP: Thank you.

CHAIRMAN JACOBS: Thank you. We will take a break for lunch. Come back at 1:15. 1:15 we'll be back.

(Lunch recess.)

CHAIRMAN JACOBS: We'll go back on the record and begin again after lunch.

MR. HAFF: Okay. Next on the agenda Gulf Power is going to give a presentation on their Ten-Year Site Plan.

MR. POPE: Good evening, Commissioners and ladies and gentlemen. My name is Bill Pope. I'm with Gulf Power Company, I'm the bulk power planning coordinator. And with me is Mike Marler, who will be presenting some of our forecast information. We have a brief summary presentation of Gulf's 2001 Ten-Year Site Plan. I'd like to start off with the forecasted information.

MR. MARLER: Gulf's forecast for the 2001 Ten-Year

Site Plan uses the same methods and procedures that we've used in the past. This reflects the impacts due to DSM over time. Without DSM we would expect to -- we have grown 2.8%, historically, and would be projected to grow at 1.6%. The DSM savings reflect a total of 599 gigawatt-hours by the year 2000 cumulative, and by the year 2010 it is projected to produce 829 gigawatt-hours per year.

Impact on our winter peak demand. Historically, we've grown 3.3% with the DSM impacts; would have been 3.4% compound growth rate over that same time period without. By the year 2010, our growth rate over the next ten years would be 1.8% with DSM and 2.3% without. Cumulative through the year 2000, we've achieved a total of 319 megawatts for demand savings in the winter peak, and by the year 2010 we project that to grow to a total of 528 megawatts.

CHAIRMAN JACOBS: The components of that -- what are the components of that, the DSM savings?

MR. MARLER: The components of the DSM savings?

CHAIRMAN JACOBS: Yes.

MR. MARLER: That's comprised, primarily, of our residential, commercial, and industrial programs and includes things like our Good Cents Home Program, the Good Cents Select New Home Program, also our RTP demand reductions, commercial Good Cents building programs, residential energy audits, commercial energy audits, as well as outdoor lighting conversion from mercury vapor to high pressure sodium, that's generally the programs.

CHAIRMAN JACOBS: Okay. Thank you.

MR. MARLER: That's all primarily passive DSM programs. There's no direct load control involved in this.

Similar impacts on our summer peak demand, historical growth rate about 3% compound, projected to be about 1% after the impact of our DSM programs. The cumulative savings through the year 2000 on our summer peak are just under 300 megawatts, and by the year 2010 we project that to grow to a total of 461 megawatts.

Compared to our previous site plan, there are basically no significant changes. They're identical from last year to this year in the forecast period. Historical growth rate on energy for load is 2.7%, and we're projecting that to be 1.4%.

Our winter peak demand projections, historically, you can see some of the volatility involved with winter peak demand. Again, there's not a very significant difference from last year's site plan to this year's, with some minor corrections in the short term due to model calibrations. Historical growth rate has been 3.3%, and the compound average annual projected growth rate is 1.8%.

Our summer peak demand forecast reflects a historical growth rate of 3%, and our projected growth rate under this new site plan is at 1% compared to .9% in last year's forecast. There's very little change this year from last year.

Mr. Pope will present our plan.

MR. POPE: I'd like to summarize the --

COMMISSIONER DEASON: Excuse me. Before we leave that, I'm just trying to understand the comparison of your forecasted growth rates with your historical and the forecast appears to be a lot lower. Now, I understand that some of that could be attributed to the fact that you have a larger base and, therefore, it could be a smaller percentage increase, but growing in the same absolute terms, but it just seems to be a big difference between historical and projected. Could you explain what that difference is?

MR. MARLER: The primary impact in the projected period has to do with increased implementation in our DSM programs under the residential sector, and it has a significant impact on both the summer peak and the winter peak demand. Traditionally, we had about 50 megawatts a year in peak demand, and with our DSM programs in the summertime they reduce that growth by about 20 megawatts a year, and in the wintertime it's about 25 megawatts a year reduction, so it just about halves our growth rate.

Additionally, in the historical period a lot of the additions weren't as efficient as the newer additions are with the new billing standards, things of that nature, and that's the primary causes of it, the economic outlook. Our customer growth is not significantly less than it was in last year's Ten-Year Site Plan. It's slowing somewhat over the forecast horizon because of the economic outlook primarily, but the main driver is in the DSM programs.

COMMISSIONER DEASON: Well, if we just ignore DSM, though; for example, I'm looking at your summer peak forecast. If I'm reading this correctly, if you ignore DSM, it still is 1 1/2% compared to 3.3% historical. And you say that's primarily attributable to a change in economics and change --

MR. MARLER: Well, in the difference in the base numbers there, yes, sir.

COMMISSIONER DEASON: Have you made any changes to your basic forecast methodology or made any significant changes in the way you go about doing it or just these are the numbers that fall out from your calculation?

MR. MARLER: These are the numbers that fall out. I did a calculation without DSM. Over the past ten years -- excuse me, over the projected ten years is about 46 megawatts annually that we had in peaking summer capacity -- I mean, summer demand. And historically, there has been about 45 megawatts over the past 20 years, so they're not very far different from one another. It just appears that way, mostly because of the base number.

COMMISSIONER DEASON: Thank you.

MR. POPE: Here is a summary of the unit additions and retirement over the planning horizon, starting with June of 2002, with the addition of Smith Unit 3, it's a 574-megawatt combined cycle unit. The next addition projected will be June 2005, and it's currently projected as a combustion turbine to be installed in the same Smith site of 157 megawatts. And then in December, the end of December 2006, Lansing Smith Unit A, which is a 32-megawatt combustion turbine is going to retire. And then, the final addition is a Southern generic -- a participation in the Southern generic combined cycle unit in the year 2007.

Those are the only additions and retirements we have in the planning horizon. And what that looks like on an overall basis is summarized, and I apologize for this quite busy table, but starting in 2001 and going through the planning horizon, first column shows what you expect to have as total installed capacity.

Let me see if I can clear that up a little bit. Nope. The next column would be the imports or NUG capacity, plus interruptibles. The next column is entitled, Capacity Additions, that's where you'll see the additions --

COMMISSIONER DEASON: Excuse me. Can you go back to the previous column and explain the change from 2001 to 2002?

MR. POPE: Yes, I'll be glad to. The 489 is a composite of purchases that Gulf has entered into for this year, 2000 -- well, some that have been before, but also some strips for year 2001 summer. Those expire -- all of those will expire by the end of May 2002, so they do show up as a resource in this year. In addition to those purchases, there is about 26 megawatts of interruptible and 19 megawatts of NUG in the next 45. All of that goes away except for the 45, so the big -- the 489,000 -- or 489 megawatts, all of but 45 megawatts is purchases.

COMMISSIONER DEASON: Now, were these purchases that you entered into contemplating that the Smith unit would be coming on-line and that those purchases then could go away? It was a timing thing or what was --

MR. POPE: Actually, the Smith unit was needed to take the place of those purchases. Some of them were made some time ago and expired May 31st of 2002.

COMMISSIONER DEASON: Okay.

MR. POPE: All right. Next column is capacity additions, and that's where you'll see your capacity additions. And you'll also notice a couple negative numbers. The 574 megawatts of combined cycle unit as other units degrades, and that's what those negative numbers are. The initial capacity is 574, and you'll see some degrading. Also, in the year 2007, the 28 is a composite of 60 megawatts of additional capacity with the retirement of Smith A of 32, so that's -- I want to explain that.

COMMISSIONER JABER: But does that mean that you will not be entering into contracts for capacity? There will not be any capacity additions in 2003 and 2004?

MR. POPE: That's correct. We're not projecting any capacity additions for those two years.

COMMISSIONER JABER: And then for those two years, though, it's also your estimate that you will be meeting demand through every peak season.

MR. POPE: That's correct. If you'll look in the last two columns, your reserve margins, your reserve margins are still staying up to where you can meet your demand.

COMMISSIONER JABER: These reserves are below 15%.

MR. POPE: That's correct.

COMMISSIONER JABER: So, this does not take into account your curtailable or your --

MR. POPE: We don't have any direct load control or load management. We have one interruptible that's reflected in this column here that's actually around 26 megawatts, and that is already taken out of, so it is considered in the reserve margins already.

COMMISSIONER JABER: Remind me, Gulf Power was not one of the companies that volunteered to increase its reserves to 20%, right?

MR. POPE: We weren't part of that. That was restricted to or limited to peninsular Florida.

COMMISSIONER JABER: Do you have any pending contracts with merchant companies or any other generation companies?

MR. POPE: Not at this time.

COMMISSIONER DEASON: What is your planning criterion? Do you use a reserve or do you use loss of load or do you just tie it into the Southern system and rely on them?

MR. POPE: Well, let me explain that, because it is tied into the Southern Electric System, but it does depend on what we call expected unserved energy. The expected unserved energy drives the economics for what is the economic choice of generating percent reserves. And the components there are what it takes to cover unexpected unit outages, unexpected weather conditions, which drives your load up, and forecast error.

And when considering all those together in the probabilistic form to come up with unexpected, unserved energy, on the Southern Electric System that target reserve margin ends up being 15%, and that's what we use on Southern Electric System as our target reserve margin, our minimum. That's for the planning horizon which really, for decision purposes, is the fourth year out and beyond.

In the three years closest to you; that is, the current year plus two years, it's a minimum of 13 1/2%, because your risk and uncertainty is reduced for that near term as opposed to the fourth year and beyond for generation planning purposes.

COMMISSIONER PALECKI: So that applies to the entire Southern System?

MR. POPE: That's correct, and that's what's reflected in the very far right column. You'll see that Gulf's reserves move quite a bit in comparison to that, and that's because Gulf is a relatively small system in and of itself, and economic choices of additions are rather large when compared to Gulf's load. That's why we share a significant benefit for being part of the Southern Electric System.

COMMISSIONER PALECKI: Well, could you explain that? How does Gulf benefit from the Southern reserves?

MR. POPE: We're part of the Southern Electric pool, a central dispatch pool, which plans for the whole Southern Electric System on a 15% reserve margin target. Since we are part of that pool, we can plan to share in those excesses and surpluses, the temporary excesses and surpluses to us.

I mean, our temporary excesses and surpluses are shared in the Southern Electric pool. Georgia Power one year, because it's economic for them to install a 500 or two 500-megawatt combined cycles, will have enough to cover part of Mississippi's and Savannah's and Gulf's needs. And then later on when it's more economical and we have a big enough need, we can install a 500-megawatt, and some of that excess will go back into the Southern Electric pool. It's a sharing arrangement where over time it makes the best economic sense.

COMMISSIONER PALECKI: So, if Gulf Power has a peak day and it has already used -- let's say, for the year 2001 it's already up to its 11.6% reserve margin, if there is reserve in a Southern Company that, let's say that other states don't share the same peak day, then Gulf Power can go ahead and utilize those reserves.

MR. POPE: That's correct. It will come to us automatically.

MR. HAFF: Mr. Pope, is Southern reserve's column on the far right, is that a target reserve or is that what's forecasted over the next ten years for the Southern System?

MR. POPE: That's what's forecasted, and it is the target. They're one in the same. There's a minimum reserve margin.

MR. HAFF: I guess, I just expect it to fluctuate some as Southern adds units and retires units. I guess, is the system so large --

MR. POPE: It's so large that your unit additions, the sizes that you're buying don't make it fluctuate that much. We're talking about a 36,000-megawatt peaking system.

MR. HAFF: Do you know, approximately, how many megawatts per year the load growth is on Southern System as a whole?

MR. POPE: Per year?

MR. HAFF: Per year; I mean, approximately.

MR. POPE: Approximately, 720 megawatts a year.

MR. HAFF: Okay.

CHAIRMAN JACOBS: Do you -- are you aware if Southern does any kind of a forecast assessment similar or like what we heard today that FRCC has done?

MR. POPE: With regard to --

CHAIRMAN JACOBS: Looking at the -- going back after the projections have come due and determining how accurate the initial projections were?

MR. POPE: A look back to see how accurate our forecasts and our plans were --

CHAIRMAN JACOBS: Right.

MR. POPE: -- I believe they do go back and weather normalize and adjust, and taking into consideration the weather conditions that were existing at the time to determine -- and that is a factor in determining our forecast error, which is an adjustment, we adjust our forecast based on those.

CHAIRMAN JACOBS: Thank you.

COMMISSIONER DEASON: The -- your anticipated addition of a combustion turbine at the Smith site in '05, is that something you will issue an RFP or have you already made that decision?

MR. POPE: We have not finalized that decision, but it is not required under that rule to have an RFP issue --

COMMISSIONER DEASON: Because it's a combustion turbine?

MR. POPE: Yeah, at this time it's not required.

COMMISSIONER DEASON: So, even though it's not required -- I guess, my question is you're not going to issue an RFP unless it's required?

MR. POPE: We're not planning on it right now. I'm not so sure that we wouldn't try to test the market to see if something is cheaper out there. We do that all the time anyway, but a formal RFP, I don't believe, is anticipated at this time.

MR. HAFF: I just have one more clarifying question, I guess. I understand that we talked in the past that Southern does a full-blown integrated resource plan every year with updates in the interim. During what year will be the next full-blown RFP?

MR. POPE: 2001 was the full-blown --

MR. HAFF: This one was?

MR. POPE: Yes.

MR. HAFF: Okay. Is there any questions for Gulf Power?

MR. POPE: Thank you, Commissioners.

CHAIRMAN JACOBS: Thank you.

MR. HAFF: Thank you. Thank you for coming.

MR. HAFF: Next we're going to hear from Tampa

Electric Company. I guess, now would be a good point to interject. I know there's, you know, the munis and Seminole are here. And as we have in the past, you're free to present as much, I guess, or as little as you want. If you prefer just to have -- be available for questions, I think, the Commissioners are amenable to that. When it's your turn, I'll just leave it up to you, I guess, to decide what you're going to do.

MR. SMOTHERMAN: My name is Bill Smotherman. I'm with Tampa Electric Company. I'm the Manager of Resource Planning at Tampa Electric Company, and I am here to give a brief summary of Tampa Electric's Ten-Year Site Plan. I'm going to start out a little bit with the load forecast information and switch over to our DSM, talk about our plan a little bit and the major changes that have occurred since last year.

This first slide is a comparison of our total retail peak for the summer from starting with historical data in 1990 through forecasted data of 2010. It also has not only the present forecast but also last year's forecast. It's very hard to see any differences in the two lines merely because the forecasts are very, very close. There's not a lot of difference between last year's forecast and this year's forecast on load. The methods and data utilized for this are fairly similar. There's no major changes in processes associated with these. The overall growth rate associated with our forecasted peak has been about 2 1/2%.

COMMISSIONER DEASON: Let me ask the question. I see that this is your retail peak, so it excludes any wholesale. How do you plan for your wholesale need?

MR. SMOTHERMAN: Essentially, for wholesale sales, they are wholesale sales we have which are PR contracts, and those are forecasted in a very similar manner for the ones that are of that nature. As far as for sales that we have from a block nature, we have a sale with Florida Power Corp., for example, the amount of demand on that sale is predetermined for most of those and the energy is based on a contracted pre-specified amount. And, essentially, what Tampa Electric does is forecast the other company's usage of that sale based on the economics we feel are in market at the time.

COMMISSIONER DEASON: But you've got to incorporate your wholesale needs with your retail to determine what type of plants need to be constructed and in what time frame, correct?

MR. SMOTHERMAN: That is correct. And for wholesale sales we assume that they are taking the power that we sold them on peak so we, essentially, are making sure that we're not counting on megawatts that aren't necessarily there when we would need them for retail customers.

COMMISSIONER DEASON: Okay.

COMMISSIONER JABER: What was the statement you made about the 2 1/2%?

MR. SMOTHERMAN: That is roughly our growth rate over the ten-year forecast period.

COMMISSIONER JABER: Okay. So, from 2001 to 2010 the growth rate, in terms of demand, you estimate to be 2 1/2%?

MR. SMOTHERMAN: That's correct.

COMMISSIONER JABER: Okay. That doesn't seem to square, if I -- just to take in isolation with the increase in the population in the next ten years, that doesn't really square with 2 1/2% increase in demand, does it?

MR. SMOTHERMAN: When you --

COMMISSIONER JABER: Seems like that number should be higher.

MR. SMOTHERMAN: When you say doesn't square with the population, what are you referring to?

COMMISSIONER JABER: What population data do you use?

MR. SMOTHERMAN: We use the same population data as the overall state data and I'm not familiar with the details of that, but it's essentially the BEBR forecast.

COMMISSIONER JABER: Do you remember what the forecast is for the percentage increase in the next ten years just in population?

MR. SMOTHERMAN: I'm not aware of where our service territory is, particularly, and how that compares to the overall state.

COMMISSIONER JABER: Okay.

MR. SMOTHERMAN: Tampa Electric's service territory is fairly confined. We serve most of the Tampa Bay region with some areas in Pasco County and some other developing counties, but our overall area is not expansive, so to speak, it's fairly confined.

COMMISSIONER JABER: You're impacted a little bit by the I-4 technology corridor, right?

MR. SMOTHERMAN: That is correct.

COMMISSIONER JABER: And your forecasts have taken that into account?

MR. SMOTHERMAN: Yes, they have.

COMMISSIONER JABER: How so?

MR. SMOTHERMAN: I'm not familiar with, again, the details of that but I know that those are taken into account in the forecast with specific customers that have had contact with us, as well as just general.

COMMISSIONER JABER: So, if a customer -- if a customer's establishing a business, technology or otherwise, in the TECO region they would, of course, come to you and tell you what their demand needs are.

MR. SMOTHERMAN: That is correct.

COMMISSIONER JABER: Do you do any sort of survey in the area to try to better understand projected need with existing businesses as well?

MR. SMOTHERMAN: Yes, we do. In fact, we've got -- our first contact, generally, on actual demands associated with specific larger customers come from our contacts, both from a customer perspective as well as from our business perspective.

We've got contacts with customer salespeople that we have with our larger customers and with -- very good contacts with economic development agencies where we're trying to actually attract certain types of customers to the area. So there's a lot of interaction that occurs in that forecast, and our load forecasters take that information into account.

COMMISSIONER JABER: Did Tampa -- is it final, the Olympic 2012 or whatever?

MR. SMOTHERMAN: No.

COMMISSIONER JABER: Is that finalized for Tampa?

MR. SMOTHERMAN: That is not finalized yet.

COMMISSIONER JABER: It's not finalized?

MR. SMOTHERMAN: No.

COMMISSIONER JABER: Have you thought about any of that in terms of year-long planning?

MR. SMOTHERMAN: We haven't started incorporating what would happen there but, obviously, there would be a large demand increase associated with that, with those facilities being built, if we are successful in getting that, and we would adjust our plans accordingly.

This is the same exact graph similar to the summer, except it shows the winter. And as you'll notice that the historical winters are up and down as merely a result of when we actually have a winter from the standpoint of real winter weather versus when we have a more milder winter, and you'll see from the forecasted perspective that nice straight line, that's a nice straight line merely because we're forecasting on a weather normalized basis, so we're always assuming that we're going to have some level of winter weather, but from a historical perspective it's fairly obvious that that doesn't always occur.

This next graph is a pie graph for 2001 and 2010 to give a feel for how much demand-side resources Tampa Electric is counting on, and it's broken up into four major pieces there. There is the load management, interruptible, self-service cogeneration, and conservation. The megawatts that grow there is essentially about a 5% growth, and it starts out at 655 megawatts growing to 682 megawatts. The interruptible segment actually decreases, and that is picked up actually from growth in other areas.

You'll notice that load management stays, from a percentage basis, fairly constant. It actually grows slightly, but from an overall pie perspective it's about the same. The largest growth that we see is in the conservation area, and those conservation growth numbers there are reflective of past programs, not the interruptible or the load management offerings.

We've got a similar slide here for the winter. And, again, you'll notice that we've got it broken up in the same four areas. The megawatts are much higher over the winter merely because a lot of the types of programs that are implemented actually give to you more bang for the buck over the winter than the summer. Again, conservation is showing the highest growth, load management is fairly constant, and interruptible is dropping merely because of reduction in phosphate load out through time.

COMMISSIONER PALECKI: Is there a particular program or programs that is responsible for a major percentage of that conservation increase?

MR. SMOTHERMAN: They're kind of spread over many programs, and I'm not sure what the highest contributor is to that pie right now, but it is fairly widespread over many, many programs there.

COMMISSIONER PALECKI: Because that's a huge piece of the pie in 2010. It's almost 50%.

MR. SMOTHERMAN: Yes, it is.

I want to switch a little bit and talk about our expansion plan now from a capacity perspective and kind of highlight some of the major changes that have occurred between our last Ten-Year Site Plan filing and this Ten-Year Site Plan filing.

Starting off, we've got retirements that we're doing related to an agreement that we have with the EPA regarding the Gannon Coal units. And that agreement, basically, requires that we retire some of the Gannon assets and also repower some of the Gannon assets. What we've done is actually extend the retirement dates of Gannon 1 through 4 through to December of 2004. The reason for that is in the original consent decree, which is the EPA filing, they allowed us to retire those units as late as December of '04. And what we've decided to do is go ahead and show that as our planning numbers.

In the earlier values that we show, we had them retiring out earlier to stay closer to a 20% reserve margin, but given the fact that there may be opportunities from the standpoint of making additional sales over that period that customers can take advantage of or to the standpoint of just improving overall system reliability we decided to go ahead and show those at the later dates.

We've also got a small CT; again, CT 1, which was retired effective January 2001. This was a 17-megawatt combustion turbine that had suffered some major lightning damage late in the summer of 2000, and after an evaluation it was decided, given the size of the unit and the pending changes in 2003, 2004, that it would be better not to go ahead and repair that unit but to go head and retire it.

For Hookers Point station, Hookers Point Unit 5 was placed on long-term reserve shutdown, and the remainder of the station was limited to 100 megawatts. These changes and limitations were based on as a unit gets towards the end of its physical life, it's starting to degrade and have a lot of maintenance type issues as well as capital issues. And given that we're getting ready to, again, infuse a large megawatt into the system in 2003 and 2004, we thought it better not to try and get those megawatts back at this time and let them go, especially seeing that we're getting ready to retire this station.

Finally, Bayside Unit 2, which was a repowering of one of our Gannon CTs -- Gannon combined cy-- let me start all over. Bayside 2, which is the repowering of our Gannon Unit 6 was switched from a 3 CT repowering to a 4 CT repowering. And, essentially, in further study in looking at the unit closer, it was determined that we could put an extra CT into repowering, eventually taking advantage of more of the Gannon assets there making a larger unit, improving the overall reliability of the unit by having more units -- repowered CTs with it, so we decided to go ahead and make that change to that unit.

This slide gives a summary of our summer reserve margins comparing last year's Ten-Year Site Plans to this year's Ten-Year Site Plans. You'll notice that the very last year on last year's Ten-Year Site Plan is N/A, because the Ten-Year Site Plan ended in 2009 and that continues on, obviously, for this year. The changes that you see for 2002, you'll notice that we dropped from a 21% reserve margin in 2002 to an 18% reserve margin in 2002. That is driven solely by the reduction in megawatts from the Hookers Point unit, as well as the retirement of the small Gannon CT.

In 2003 and beyond, you'll notice that we maintained a reserve margin of 20% or higher. You'll notice that 2003 and 2004 have significant increases in the reserve margins. Those are merely due to the fact that a change in retirements of the Gannon 1 through 4 units.

MR. HAFF: I have a question. I see there are summer numbers on that table. The winter -- for the upcoming winter in your Ten-Year Site Plan you show a reserve margin of 15%, but my -- in looking through here I discover there's 40 megawatts of unspecified purchases, at least for this winter season, and if you were to account for those and take them out, the actual reserve margin looks like 14%, and I was wanting to know what Tampa Electric is doing to address this upcoming winter season.

MR. SMOTHERMAN: We have already signed a contract for a 50-megawatt purchase to cover those winter reserves, and that has been attained.

MR. HAFF: Okay.

MR. SMOTHERMAN: So, we are actually a little bit better from a reserve margin perspective.

MR. HAFF: I'm sorry, who with?

MR. SMOTHERMAN: I'm not positive of it. I think, it's Aquila is the party that we've got the contract with. I'm not positive of that.

MR. HAFF: Repeat that again.

MR. SMOTHERMAN: Aquila, it's a power marketer; it's buying capacity from someone else and selling it to us.

MR. HAFF: So, it's likely coming from out of state, then?

MR. SMOTHERMAN: No, it's actually, I think, in state. They've bought capacity from somebody in state and they're reselling it.

MR. HAFF: All right. Thank you.

COMMISSIONER DEASON: What are your 2001 numbers without load management and interruptible?

MR. SMOTHERMAN: 2001, I believe, are around 7%.

COMMISSIONER DEASON: 7?

MR. SMOTHERMAN: 7%.

COMMISSIONER DEASON: And you say for 2001 -- what about for 2002?

MR. SMOTHERMAN: 2002 are around the same percentage. We grow -- once we're at about a 20% reserve margin that becomes equivalent to about 12%, so over the entire period we grow up to about 12%. Over the early years, we're at about 7. In 2003 and 2004, we're significantly higher than that merely because our overall reserve margin is so much higher. Looking at it from a megawatt perspective, this gives an idea of the mix of resources, capacity resources, that we presently have in our system.

In 2001, Big Bend represents about 40% of our overall system capacity. Gannon Coal station represents about 24%; that's followed by Polk, which is about 8.6, and that's the integrated gasification unit is there, as well as a CT presently. Hookers Point represents about 2%; 10% to 11% from purchases, and 14% from DSM programs, which are controllable programs.

The .9% of the other is a small #6 oil plant that we have, Phillips, brings up the remainder of that. And as we go into 2010, you'll notice that there is a change where Bayside replaces the Gannon station capacity, plus additional. At that time, Bayside will represent about 28 1/2%, Big Bend will drop to about 32%, Polk will represent about 9.6, and included in that is, again, the Polk 1 gasification unit as well as two additional CTs. We have a need for future CTs, or as we've listed it right now of about 10 1/2%, and 6.4% related to purchases, and then DSM programs representing about 12%.

COMMISSIONER JABER: The 4,660 megawatts is what you have available this summer 2001?

MR. SMOTHERMAN: That's correct.

COMMISSIONER JABER: And how has TECO done? What has been the demand this summer?

MR. SMOTHERMAN: Actually, we've had a relatively mild summer. We've had a lot of rain in our service territory, which we haven't had over the past couple summers, so our overall demand has been fairly mild for us this summer.

COMMISSIONER JABER: Do you have a number of mega--

MR. SMOTHERMAN: I don't have an exact number for you. I know it's around 3,400 range, but I don't know the exact number for it.

COMMISSIONER JABER: And do you know how that compared to what you expected last year, how you forecasted for this summer?

MR. SMOTHERMAN: It's actually probably on the order of about 100 megawatts less, I would guess. The summer's not over. Obviously, we've got to get through August, and our summer period could run anywhere from June through August, September, so we have yet to make it through the entire summer.

This pie graph represents the identical information shown for the winter of 2000 and 2001, as well as the winter of '09 and 2010. The numbers are fairly similar. Big Bend starts out at about 35, Polk at about 8, Gannon about 21%, purchases representing about 11%, and DSM representing about 22.

Probably the biggest difference in these two charts is the fact that the DSM represents a bigger portion of the overall demand, merely because most of our DSM programs, mainly the load management program, we practically double the amount of megawatts we get in the winter peak versus the summer peak, which accounts for the larger reliance on DSM over the winter period versus the summer period.

Finally, we've got a generation by fuel type which, essentially, gives a feel for of the total generation that we have, how much of each fuel type serves our load on a gigawatt hour basis. Starting in 2001, presently we're about 84% coal fired, Petcoke fired, 7.6 Syngas, that represents the Polk 1 unit, the integrated gasification unit; about 7.1% is made up of purchases, about 1% oil, and about .6% natural gas, which is coming from the single CT that we have in our system, a large F-frame gas unit. In 2010, the Petcoke coal drops down to 49%; natural gas increases to about 36%. That 36% is the Bayside units. That repowering actually changes our fuel mix fairly dramatically where we have a lot more natural gas fire capacity in our system.

COMMISSIONER JABER: As part of your agreement with DEP or EPA or both did you have to look at alternative coal technologies or clean coal technology?

MR. SMOTHERMAN: No. Essentially, the agreement is framed around repowering of the Gannon station. At Big Bend what we are required to do is look at different methodologies of reducing our NOX emissions and further reducing some SO2 emissions.

And in summary, we believe the Tampa Electric Ten-Year Site Plan provides an adequate plan for maintaining system reliability for the company's customers over the planning horizon.

COMMISSIONER DEASON: I have a question. I'm looking at your summer pie chart for your integrated resources, and I notice that there's a category called Future Capacity, which comprises 10 1/2% of your overall resource mix. Do you have a plan in place which specifies how that future capacity -- how you're going to acquire that future capacity?

MR. SMOTHERMAN: Presently, in the expansion plan, we're showing future CTs as additions. Those are not required until 2006. And as we go through time, we will probably reevaluate how we are fully going to build up that capacity, whether it be purchases, whether it be CTs that we actually construct. We'll finalize that as we get closer in on the plan.

COMMISSIONER DEASON: Does -- I know that that's a ways off, but does TECO routinely engage in reviewing the potential of additional coal capacity on its system?

MR. SMOTHERMAN: We review coal, gas, CTs, essentially, all the different types of technologies.

COMMISSIONER DEASON: So, you have not ruled out anything.

MR. SMOTHERMAN: No, we have not ruled out anything.

MR. HAFF: I'd just like to clarify something from Commissioner Deason's question about the future capacity. That's the string of combustion turbine units in your Ten-Year Site Plan, right?

MR. SMOTHERMAN: That's correct.

MR. HAFF: As opposed to an unspecified purchase. This isn't an unspecified purchase.

MR. SMOTHERMAN: No, it is not an unspecified purchase.

MR. HAFF: Okay. Thank you. Are there any questions for Tampa Electric? Okay. Thank you.

MR. SMOTHERMAN: Thank you.

MR. HAFF: Commissioners, we're coming up on the part of the workshop where there's seven municipals and a cooperative here and, I guess, with time constraints or whatever, I guess, I'd recommend we just call them up and ask them if they have any -- if anyone has any questions for them and not necessarily require a presentation.

CHAIRMAN JACOBS: Commissioners, what's your pleasure? There were two that I, specifically, wanted to ask questions.

MR. HAFF: I'd suggest we could have --

CHAIRMAN JACOBS: Have each one come up?

MR. HAFF: Call them up one at a time and ask if there's any questions for them, and if there are, go ahead and ask that person.

CHAIRMAN JACOBS: Is that okay with everyone? Okay, let's do that.

MR. HAFF: Next will be the Florida Municipal Power Agency. And I have a question for Mr. Casey. If the Commissioners have them, I'll wait.

COMMISSIONER JABER: Mike, why don't we ask them if they had been planning on doing presentations, maybe we can at least get the copy of the presentation, even if they're not going to give it.

MR. HAFF: Yes. If you have a presentation that you had brought with you, at least make sure we get a copy of it, and we appreciate that very much.

Does anyone have any questions for the Florida Municipal Power Agency? I have a couple I wanted to ask, Mr. Casey. The Ten-Year Site Plan, particularly, in the summer season starting in 2003 had a string of what we call unspecified purchases?

MR. CASEY: Right.

MR. HAFF: And in looking through the presentation, I didn't know if FMPA had come up with any plan, at least at this time, to address some of those future unspecified purchases.

MR. CASEY: We're currently negotiating with about three different parties to more than adequately fill those needs. We also have some options and existing contracts where we can increase our contract capacity, if we so choose. So, we've got lots of options.

MR. HAFF: Is it something that would be more concrete before, say, in the next few months or is it --

MR. CASEY: We should be wrapping some of these negotiations up by the end of the year, if not sooner.

MR. HAFF: Okay. Because, you know, we've been concerned in the past with the unspecified purchases, especially the larger utilities in the state.

MR. CASEY: Right.

MR. HAFF: And, I guess, what I would suggest or recommend is that as soon as something becomes signed or something becomes more firmed up, would you let us know?

MR. CASEY: Sure, be happy to.

MR. HAFF: Are you at a point in these negotiations where you're able to tell us whether the possible purchases be from in-state or out of state?

MR. CASEY: Everything we're looking at is in-state so far.

MR. HAFF: Okay. Are there any other questions for Mr. Casey?

CHAIRMAN JACOBS: I was just looking and listening, and the only major additions that you're anticipating is the McIntosh plants, correct?

MR. CASEY: Well, of course, the Cane Island 3 will be complete this summer. We've got Stanton A, which was approved by the Commission several months ago coming in in the fall of '03, and the Lakeland McIntosh 4 is planned for '05, yes, sir.

CHAIRMAN JACOBS: Okay. Very well. Thank you. No other questions? Thank you very much.

MR. CASEY: Yes, sir.

MR. HAFF: Thank you. I think -- is that all of the questions? Okay, thank you.

Next is Gainesville Regional Utilities. If you have a presentation or a hard copy, please make sure we have that. I don't have any questions of GRU. Is there any questions from the Commissioners or the audience?

CHAIRMAN JACOBS: Any questions? There are none from the audience. No questions.

MR. HAFF: Okay. Are there any questions for Gainesville? None? Okay. Thank you.

Next on the list is JEA. What I may do, Commissioners, if they have a presentation list, maybe you can take a moment to read through it, in case some questions pop up before we dismiss them, if you want to.

COMMISSIONER JABER: I have one question. Is JEA impacted by the NAP of Jacksonville?

MR. BOND: Actually, we are meeting next week. We're going to start discussing what the impact's going to be going forward. The preliminary plan is that we would be impacted in the 2003 to 2005 time frame from anywhere from 90 to 110 megawatts, so we certainly need to sit down and figure out what exactly that load may be and what type of generation or reliability that company may need to have and that might dictate whether we, you know, serve it with a big unit or distributed generation or, you know, there's lots of options, so we'll start evaluating that going forward.

COMMISSIONER JABER: Is it also supposed to be sort of a Teleco hotel kind of set-up, do you know?

MR. BOND: I don't, specifically, know any of the detailed plans on that. They typically kind of advise us of the loads, but our planning group kind of handles the details of the negotiation, so I'm meeting with our planning group next week to try to get a handle on this.

COMMISSIONER JABER: Thank you.

CHAIRMAN JACOBS: In 2002 and 2004, looks like is that -- is your chart depicting that you're falling just below the 15% for -- this is the peak -- winter peak?

MR. BOND: On -- I was -- I didn't hear your question.

CHAIRMAN JACOBS: I'm looking at the last page of your handout.

MR. BOND: Okay.

CHAIRMAN JACOBS: And it looks like on 2002 and 2004, that is -- do you know what your -- I guess that is the peak plus 15%, that line that you're falling just beneath? What's your capacity on that?

MR. BOND: Correct. And then, that's right at the 15% reserve margin which we use for planning, and that's because for those two particular years we will be taking our Northside Unit 1 out for repowering, so we'll have the seasonal purchase in that winter, which will bring it up right to the 15%. And then in 2004, as part of our Brandy Branch conversion we have to have more time between seasons, so we'll be taking two of our combustion turbines out for conversion to combined cycle during that winter period, because it's usually easier for us to get capacity with our proximity to the tie line in Georgia, so we pick the winter seasons to take those units out for those conversions, and then we'd purchase up to our reserve margin requirements.

CHAIRMAN JACOBS: I see. And those have been identified, I assume.

MR. BOND: No, they have not been identified. Typically, we start about this time of year working with The Energy Authority with our tie line capability and usually we get a good portion of our reserves out of Georgia, a lot of times from MEAG, which is a member utility and The Energy Authority with us. And usually, when we have our capacity for that season acquired, we inform the Staff of where those megawatts are coming from and who we've contracted with to get those megawatts.

CHAIRMAN JACOBS: Thank you.

COMMISSIONER DEASON: I have a question. On the year 2010, under the category of Greenfield units, you have a unit specified there. What is CFB?

MR. BOND: That's a circulating fluidized bed unit, that's similar to the technology that we're using to repower our Northside Units 1 and 2 at our Northside station and that, basically, this year's plan, that was driven by the fact of at the time we're doing our plan our natural gas forecast was kind of running high so, actually, that coal technology for that size unit was out that far in the future was our least cost alternative for 2010.

COMMISSIONER JABER: Circulating what?

COMMISSIONER DEASON: Circulating fluid --

MR. BOND: Circulating fluidized bed.

COMMISSIONER DEASON: You looked at cost information, which indicated that it would be your least cost option in 2010?

MR. BOND: Right. With what we had predicted as our long-term fuel forecast, natural gas prices as they were going up in price and escalating, the coal technology became less expensive for us as an alternative based on what we know today as fuel forecast. In that unit, so far out, we would probably not anticipate even starting permitting for a unit that far out for several more years, and it's that liable to change based on what our long-term fuel forecast how it would fluctuate in the future years.

COMMISSIONER DEASON: So, the primary driver there is anticipated increase in natural gas prices, correct?

MR. BOND: Correct.

COMMISSIONER DEASON: Did you factor in any anticipated improvements in the technology or is this based upon the technology as it currently exists?

MR. BOND: This is pretty much the technology as it currently exists, which is a pretty advanced technology. The units that we'll be building at Northside will be the largest ones in the world when they're completed, so for that size unit and this technology, that is the clean coal technology that's out there at the present time.

COMMISSIONER DEASON: Thank you.

MR. HAFF: Are there any other questions for JEA? Okay, thank you.

MR. BOND: Thank you.

CHAIRMAN JACOBS: Thank you.

MR. HAFF: Next we're going to have Kissimmee Utility Authority. I have a couple of questions as he's passing that out. I'll wait for him to pass out his notes.

MR. MILLER: Good afternoon. My name is Robert

Miller, and I'm Manager of Bulk System Planning at Kissimmee Utility Authority.

CHAIRMAN JACOBS: I think, we'll just take the questions. Mr. Haff.

MR. HAFF: Yes, I have some questions regarding some -- what looks like unspecified purchases in 2008, 2009, and 2010, looks like seven megawatts in 2008, 20 megawatts in 2009, and 32 megawatts in 2010. First off, are those numbers right?

MR. MILLER: Yes, they are.

MR. HAFF: And what has KUA done, I guess, up to this point to address that?

MR. MILLER: Currently we're not negotiating with anyone. We've got some contracts that have options that we could exercise to get these, but that wouldn't necessarily be the most economic thing for us, but --

MR. HAFF: Is the existing contracts that would expire, say, in 2007 or something?

MR. MILLER: We currently don't have an expiration date on them.

MR. HAFF: Okay.

MR. MILLER: But there are options that we could exercise from within the state.

MR. HAFF: Okay.

MR. MILLER: But we fully intend to do an expansion plan this current year, and we do one every four or five years.

MR. HAFF: Okay. So, I guess, the full-blown expansion plan will be upcoming for the next year's Ten-Year Site Plan?

MR. MILLER: Yes, if we're completed by that time.

MR. HAFF: Okay. Are there any questions for Mr. Miller?

CHAIRMAN JACOBS: Question. On your fuel forecast -- fuel price forecast, hopefully those natural gas prices are coming down?

MR. MILLER: Yes. This was -- our forecast was done by DRI McGraw Hill, and it was done at a time when prices were very high.

CHAIRMAN JACOBS: When prices spiked?

MR. MILLER: Yes.

CHAIRMAN JACOBS: Great, good. Good that they spiked and they're coming down now.

MR. MILLER: Yes.

CHAIRMAN JACOBS: Thank you.

MR. HAFF: Are there anymore questions for Kissimmee Utility Authority? Okay. Well, thank you, Mr. Miller.

MR. MILLER: Thank you.

MR. HAFF: Next up is the City of Tallahassee. I just realized I went out of order, so after Tallahassee -- we'll take up OUC after Tallahassee. And then, something else for the Commission who may have had an agenda for the workshop.

The City of Lakeland was not going to give a formal presentation. Mr. Stanfield was here earlier. I don't see him now. If there's any questions, I guess, I could bring them up to him personally, but I didn't have anything to ask him.

And I have a of couple questions for Mr. Clark. It's the unspecified purchases thing again. If I did the math right in your Ten-Year Site Plan you're expecting for the summer, for this current summer, '04, '09, and 2010, and the amounts are small, but do you just want to tell the Commissioners what is being done about -- or where you are in your planning process to address those?

MR. CLARK: Sure. If you'll recall, last year pretty much all of our future needs were put forth in this way shown as unspecified purchases or yet undetermined capacity additions, generating capacity additions, or enhancements. That total need over the planning horizon has been reduced rather significantly by a reflection of a couple of quick-start combustion turbines. The outstanding amounts, 15 megawatts in 2004, I believe, it's another 8 megawatts in 2009, 24 megawatts in 2010.

We believe that the flexibility in terms of scheduling the construction of the combustion turbines will allow us possibly to accelerate their in-service date possibly to satisfy the small need in 2004, the latter needs in 2009, and 2010 could conceivably also be met by other generating capacity additions that we're contemplating.

We have not entered into any negotiations with any parties to make these purchases. We do do periodic surveys of the market; however, in light of the prices -- spike in gas prices that we've seen over the last year and how that's translated into elevated purchase price projections, we didn't feel like it was prudent to enter into anything as of this time.

MR. HAFF: Now, your planning criterion is still 17% reserve margin?

MR. CLARK: That's correct. Our long-range load reserve margin criteria is 17%; however, we are, in keeping with the stipulation of the IOUs, contemplating going to 20% also in 2004. We've contracted with a consultant to review the current 17% reserve margin criterion, as well as looking at an alternate level or maybe an alternate index, possibly loss of load probability being more appropriate for our system.

MR. HAFF: Is that a study you expect would be completed in time for next year's Ten-Year Site Plan?

MR. CLARK: Yes. Our current plans are for this resource planning study be completed sometime this fall.

MR. HAFF: Okay. They result in a potentially different looking expansion plan for next year.

MR. CLARK: I think that the combustion turbines will show up in the mix of resource additions, regardless of what the balance -- how the balance of the need will be satisfied.

MR. HAFF: Okay.

MR. CLARK: We just feel there's a great deal of operational flexibility that the combustion turbines bring to us and that we do not presently have any quick-start capability. We're currently carrying all of our operating reserves as spinning reserves. This would reduce our daily operating costs immediately.

It would also free up some of our import transmission capability that we have historically reserved for our worst single generation contingency loss of largest unit; with the addition of last year, now we have two virtually equal-sized units making up about 2/3 of our system. So we feel like we need to be able to depend on local generation a little bit more in the future for backing up those contingencies. Also, to use that as a means to be able to buy against those combustion turbines and diversifying our resource portfolio.

COMMISSIONER JABER: I didn't catch your name, I'm sorry.

MR. CLARK: I'm sorry, Paul Clark, Chief Planning Engineer, City of Tallahassee.

COMMISSIONER JABER: Clark?

MR. CLARK: Clark, C-l-a-r-k.

COMMISSIONER JABER: Last year, as I recall, we found your plan conditionally suitable, I think.

MR. CLARK: After it was all said and done, yes.

COMMISSIONER JABER: That's right. How have you this year addressed those concerns that we have?

MR. CLARK: We specifically identified two 50-megawatt aero-derivative combustion turbines as part of our resource plan for the next ten years, we have entertained presentations from five manufacturers, and we're currently putting together presentation materials to take the approval of that -- of those combustion turbines before our city commission and before the community.

COMMISSIONER JABER: On your presentation material, Page 18 looks like a presentation that you wanted to make to us about the future changes in the electric industry. Can you kind of summarize what that part of the presentation was going to be?

MR. CLARK: Just again, just strategic considerations, things we have to kind of keep in the back of our mind when we're putting together plans, that it's a possibility that we could lose our tax exempt financing status and the possibility that any decisions that we make now, in terms of major investments, could conceivably end up being stranded.

COMMISSIONER JABER: As it relates to your concern over the RTO, what would your concern be over an RTO?

MR. CLARK: Particularly, a cost issue. We are concerned about how much the transmission component of our cost to serve might be affected by the advent of an RTO.

COMMISSIONER JABER: Okay. And what alternative fuel sources are you looking at?

MR. CLARK: As I mentioned, the quick-start combustion turbines will allow us to back up part of that worst single generation contingency that we have typically reserved firm import transmission capability for. By having those combustion turbines, then we can use that import capability then to maybe import some coal by wire or some nongas-based power supply.

MR. HAFF: Are there any questions for the City of Tallahassee? Okay. Thanks, Mr. Clark.

MR. CLARK: Thank you.

MR. HAFF: Let me backtrack and bring up Orlando Utilities Commission now. Are there any questions for OUC? I don't have any questions. Is there any other questions for Orlando? Well, thank you. Tell us who you --

COMMISSIONER DEASON: I'm sorry. I'm sorry, one quick question. Your purchase power agreements, all of those have been finalized, signed? I'm looking -- it says slide indicates "Purchase Power Agreements."

MR. BLANKNER: You're talking about under the expansion plan slide?

COMMISSIONER DEASON: Yeah, you have four listings there, Tampa Electric and three from Reliant. What's the status of those? Have all those been agreed?

MR. BLANKNER: The status of those is yes, they have been agreed upon.

MR. HAFF: Okay. Now that you've spoken, we need you to identify yourself for the record.

MR. BLANKNER: Okay. I'm sorry. Yes, my name is Matt Blankner. I'm Manager of Engineering at Orlando Utilities Commission.

MR. HAFF: Okay. Are there any other questions for Mr. Blankner? Okay. Well, thank you. Last but not least, I guess, is Seminole. Would ya'll rather go first next year? I don't have any specific questions for Seminole.

CHAIRMAN JACOBS: They get the prize for the nicest graphs.

MR. HAFF: Yeah, I agree.

CHAIRMAN JACOBS: No questions, Commissioners?

MR. HAFF: Are there any questions? Anyone? Okay. Well, thank you for hanging around.

Commissioners that is all of the utilities we had called for today's workshop. The agenda for this workshop calls for after the conclusion of utility presentations to do public presentations or comments but, I guess, I would request that -- maybe ask if there's anyone here that wants to address the Commission on the Ten-Year Site Plans.

CHAIRMAN JACOBS: Let the record reflect that we offered the opportunity for members of the audience to come up and give general comments on the site plans. No one came forward.

MR. HAFF: The only thing I would ask is just that we bring this review to you around the first of December for your approval for the final report go to the Department of Environmental Protection and to the Department of Community Affairs, and we'll be doing that again this year. And if any other issues arise that we need to let you know about, of course, we will in the interim.

COMMISSIONER JABER: Mr. Haff, you'll update the available capacity amounts by the contracts that have been entered into --

MR. HAFF: Yes, that's something we definitely will do, especially as the parties make us aware of what the actual contracts are, and we'll do that.

CHAIRMAN JACOBS: If there's nothing else, then we want to thank all the parties who have taken the time to come and give us the information today. It's been very helpful. And we will look forward to a recommendation from Staff. Thanks to everyone, and we're adjourned.

(Workshop concluded at 2:45 p.m.)

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STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, KORETTA E. FLEMING, RPR, Official Commission Reporter, do hereby certify that the Ten-Year Site Plan review workshop was heard at the time and place herein stated before the Public Service Commission.

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

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

DATED this Wednesday, August 29th, 2001.

Koretta E. Fleming

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