BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of : **DOCKET NO. UNDOCKETED**

REVIEW OF TEN YEAR SITE PLANS OF ELECTRIC UTILITIES

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PROCEEDINGS: WORKSHOP

BEFORE: CHAIRMAN J. TERRY DEASON
COMMISSIONER E. LEON JACOBS, JR.
COMMISSIONER LILA A. JABER

DATE: Wednesday, August 30, 2000

TIME: Commenced at 9:30 a.m.
Concluded at 1:12 p.m.

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

REPORTED BY: JANE FAUROT, RPR
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IN ATTENDANCE:

ROBERT ELIAS and MARLENE STERN, FPSC Division of Legal Services.

MICHAEL HAFF, FPSC Division of Safety and Electric Reliability.

KEN WILEY, HENRY SOUTHWICKE and JOHN CURRIER, representing Florida Reliability Coordinating Council.

MARIO VILLAR, TOM SANDERS, LEO GREEN and STEVE SIM, representing Florida Power and Light Company.

BEN CRISP and JOHN FLYNN, representing Florida Power Corporation.

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

WILLIAM A. SMOTHERMAN, Tampa Electric Company.

TODD KAMHOOT and ROGER WESTFALL, representing Gainesville Regional Utilities.

CHUCK BOND, representing Jacksonville Electric Authority.

ROBERT MILLER, representing Kissimmee Utility Authority.

PAUL ELWING, representing the City of Lakeland.

IN ATTENDANCE CONTINUED:

MYRON ROLLINS and MATT BLANKNER, representing Orlando Utilities Commission.

PAUL CLARK, representing the City of Tallahassee.

GARL S. ZIMMERMAN, representing Seminole Electric Cooperative.

MICHAEL GREEN, representing Duke Energy/New Smyrna.

RICK CASEY, representing Florida Municipal Power Agency.

JOHN MOYLE, JR., representing Okeechobee Generating Company.

ELLIOTT LOYLESS, representing Oleander Power Project.

TIM EVES, representing Cal-Pine Construction Finance Company.

P R O C E E D I N G S

CHAIRMAN DEASON: If I could have everyone's attention, please. I'll ask you to take your places.

I'd like to take this opportunity to welcome everyone to the annual workshop concerning ten-year site plans.

We are going to follow the normal routine. We will give everyone an opportunity to address the Commission. I think staff has handed out an order of entities as they will appear, and I believe at the end of today, before we conclude, we will receive comments from the general public or other interested parties.

I don't really have much more to add than that. And with that I am just going to turn it over to staff. And if you will excuse me, I am going to have to be absent for at least the first few minutes of this, but I will be back shortly.

And with that, Staff.

MS. STERN: By notice issued by the Clerk of the Florida Public Service Commission, this meeting has been called for 9:30 a.m., on August 30th. The purpose of this workshop is to afford an opportunity for public comment on the ten-year site plan submitted by Florida's utilities.

MR. HAFF: Good morning, everyone, and thank you for your participation today. I have passed out or I have made available, I guess, sort of an order of appearance sort of -- nothing new from years past. First, we are going to hear from the FRCC, regarding the -- I guess an assessment of Peninsular of Florida and a review their load and resource plan. And I will ask questions as we go along. And if, you know, anyone, I guess, has questions, we can ask them at that time of that particular utility.

I don't have anything else now. I guess we can go ahead and start, and the FRCC can start.

MR. SOUTHWICKE: Good morning. I'm Henry Southwicke, and I'm with Florida Power Corporation. And I'm here today in my role of representing the FRCC, as the Chairman of the FRCC Reliability Assessment Group. With me on my right is John Currier from Tampa Electric, who is the Chairman of the FRCC Resource Working Group, and Ken Wiley, who is the Executive Director of the FRCC.

The resource working group that John is the chair of is the group that did the work that you are going to see the results of here this morning. It is a group of around 30 members of the FRCC that have actively participated to put this together. And with no further adieu, I will turn it over to John Currier, who will make the presentation.

MR. CURRIER: Thank you, Henry.

Good morning, Commissioners, and everybody else.

I am serving in the role as Director of Planning at Tampa Electric Company, as well as serving as chair this year of the RWG.

Our presentation is about 20 slides in total, and it breaks out into two major categories; a report on the 2000 load and resource plan, as well as the filed reliability assessment to NERC. The filed assessment includes a review of our reserve margins, a review of our forced outage rates and availability of the machines in Florida, as well as the discussion on the FGT gas transmission system and gas transportation over the next ten-year horizon.

Beginning with the load and resource report, our first slide and exhibit is the firm peak demand. And as you can see, our expected demand is going to continue to grow at about 2.4 percent both summer and winter. And it is starting at a base of approximately 35,000 megawatts in the year 2000. Growth continues up well over 40,000 over the ten-year horizon.

In comparing our forecast from last year's forecast that was presented here to the Commission, on the summer you see our starting point is somewhat similar but over time the 2000 firm plan appears to be growing at a more accelerated rate than last year's plan. You see a little bit of divergence on the out years. The winter demand almost mirrors it exactly.

Our next slide is an exhibit of the existing installed capacity in Peninsular Florida, which is approximately 35 to 36,000 megawatts, and the growth of capacity over the next ten-year horizon. And it is approximately 11,000 megawatts that are going to be added over this period of time. There is going to be significant expansion in the year 2001, 2002, 2003 and 2004 time frame. And a lot of those plants are in the utility plans, many of them are going through the permitting and construction cycle now. Virtually all of this capacity is gas-fired. It is combined cycle and CT capacity.

Our next slide is four pie charts, and we attempted to take a look at the fuel mix and how it is going to change through time in the state. The first being the -- or the first two on top is the capacity mix for the summer of 2000 and 2009. And just about every piece of the pie is going down in size relative to the other components through time, except for the natural gas component. And you can see it is going up in capacity from 25 percent to 43 percent, a sizable increase.

On the energy side, the state will soon surpass 200,000 gigawatt hours of net energy for load. That will probably occur next year. And just like the capacity side, the pies are reducing in their magnitude and size, except for the natural gas component. It is increasing from 17 percent to 41 percent of the overall service to the energy of the State of Florida.

Incidentally, another side note is the customer count in Florida over this period of time is expected to increase from 7-1/2 million today, up close to 9 million by 2009, that is overall customers.

This year the FRCC in collaboration with SERC did a review of the transfer capability in the State of Florida and published their report this past March. Last year we showed an import total capability of 3700. That has been reduced to 3600 in the summer months and -- well, actually, for all months throughout the year. On the winter transfer capability from Florida to Georgia, the assessment has indicated that there is 2600 megawatts that can go north and 2100 megawatts in the summer. Although that is not shown on there, that is the report on the total transfer capability.

Also on this page is the firm purchases, as well as the owned assets which are generally those assets that are owned by FPL and Jacksonville Electric from the Scherer Plant up in Georgia. On the far right column is the available transfer capability on the transmission grid, and that is staying fairly constant through time.

MR. HAFF: John, I've got a question. This is Michael Haff with the Commission staff. Did you say that Florida north to Georgia, that the transfer capability is 2100 megawatts summer and 2600 winter?

MR. CURRIER: That's correct, going north.

MR. HAFF: Okay. And 3600 megawatts summer and winter going south?

MR. CURRIER: Correct. It's sustained year-round.

MR. HAFF: Do you know why it was dropped from 3700? You mentioned it was 3700 last year.

MR. CURRIER: They have done an exhaustive contingency analysis, and with the folks also in Georgia. And, Michael, I frankly don't know exactly why, but I could get you a copy of that report, that might help.

MR. HAFF: Thank you.

MR. CURRIER: Thank you.

MR. BALLINGER: John? I'm sorry, another question. Tom Ballinger with the staff. You had the import. I can barely read that chart here, so I am going to ask you the question. It may be here. The import capability shown in the load and resource plan shows firm contractual commitments coming into the state, is that correct?

MR. CURRIER: Yes, uh-huh.

MR. BALLINGER: I have just been given the actual hard copy, and it shows that the net import transfer capability is a little over 1000 megawatts coming into the state, is that correct? It is your chart that you have got up on the slide up here.

MR. CURRIER: Right. That is the available transfer capability.

MR. BALLINGER: Would that be in layman's terms kind of an as-available number of transmission capability?

MR. CURRIER: That is after the firm purchases and known capacity netted against the total transfer. Now, you know, that capacity may or may not be reserved at this point, too.

MR. BALLINGER: Right. But as of right now it is not committed for any long-term purchases, and it is on the market, if you will, for -- it might be a week, it might be a day.

MR. CURRIER: Or a season.

MR. BALLINGER: Right.

MR. CURRIER: That is my understanding.

MR. BALLINGER: Okay.

MR. SOUTHWICKE: That's correct, John.

MR. BALLINGER: Thank you.

MR. CURRIER: Our next exhibit is the total dispatchable DSM throughout the State of Florida. And essentially what you see here is no growth or very flat growth throughout time. The composition also is changing slightly as you go through time. You are going to see a little bit less on the load management side and a little bit more on the interruptible side. It is a very minute change.

And effectively, and as I will show here shortly, the reserve margins have certainly increased this year's plan relative to last, which indicates that most of the reserves are now coming through physical capacity.

This is the reserves for summer and winter. We have it ranked -- or there are two lines drawn here. The FRCC standard of 15 percent, and then the investor-owned utilities' commitment to 20 percent beginning in 2004. And as you see going into next year, our summer reserves on aggregate is approximately 20 percent. So we are achieving a fairly healthy reserve margin as early as next year. And then in '03 and '04, actually through '06, we're above or near 20 percent, '03 and '04 being the highest. And then as you go through time, in the out years, it tends to come down some. But I think that is just a function that you're seven or eight years out yet, and the utilities probably will revise their plans as we get closer to that period of time.

I am going to move now to the reliability assessment. And as mentioned earlier, it is broken into three components. The trends and reserves margins, the availability and forced outage trends, and the FGT natural gas transmission system. The RWG earlier in the year met and talked and discussed whether to do an LOLP analysis this year. And the belief and feeling was at the time that if the reserves are increasing and the availability and forced outage rates are going in the proper direction, that is providing a more reliable system, that we probably do not need to do an LOLP analysis. So let me show you the results first, and then I will comment on why the RWG did not do an LOLP.

As mentioned already, the FRCC reserve standard is 15 percent and the three investor-owned utilities are committed to 20 percent by 2004 in their planning criteria. We did a side-by-side comparison of last year's plan versus this year's plan beginning with the summer reserves. The summer being the bluish-green color and last year being the more pinkish-red color. And you can see that by and large each year -- this year we are showing more reserves in the plan than last year, except for 2002. And I believe the reason for that is many of the projects that were planned for '02 in last year's plan have actually been accelerated in schedule and are coming in in '01. And you can see the big boost in '01 relative to last year.

Clearly, as you go to three and four, the years 2003 and 4, when the IOUs step up on their 20 percent commitment, you have a fairly sizable margin there on reserves.

MR. HAFF: I've got a question on that, John. This is Michael Haff again. And I guess what has caught my attention is the 2009 reserve margin. When you do the FRCC region, it shows 17 percent. I mean, IOUs make up a sizable portion of the Peninsular Florida and the state as a whole. And if they are at 20 percent, it seems to me that this number should be higher, even if all the munies were planning exactly 15, which I know they are not. Do you understand what I'm saying?

MR. CURRIER: Yes.

MR. HAFF: It seems like that ought to be higher, and just wondered if you had an answer for that.

MR. CURRIER: Yes. As we looked at that

question, Michael, the three investor-owned utilities have a sustained 20 percent level throughout the period. Some of the other utilities, some of the municipalities and co-ops are probably a little bit lower out in those out years. And I think it is just a function of -- it is pretty far out in time yet, and you can expect that. I'm sure that they will plan accordingly as they get closer to those periods of time.

COMMISSIONER JABER: I had a question for you on -- educate me again on who the companies are that are part of the FRCC? In other words, which companies go into calculation of the reserve margin?

MR. CURRIER: Do you know the names?

Yes. All the electric generating companies outside of the Panhandle. So, you know, frankly, from Tallahassee on around through Peninsular Florida make up the load component. The generating component includes all the generation of the utilities, all the contracted generation from IPPs, and then also the qualifying facilities.

MR. BALLINGER: Commissioner Jaber, if you have the attachment the 2000 load and resource plan, on Page 4 it lists the generating utilities in Florida and their amounts. So at least it gives you the feel of the utilities involved.

COMMISSIONER JABER: Thank you.

MR. CURRIER: Continuing on. As we show the winter reserves, we see a similar trend as we saw in the summer where throughout the entire forecast period we are above the FRCC standard, and we are also above the 20 percent level for six of these nine forecasted years.

Moving into the forced outage rates and availability trends, which is, you know, how available the machines are when you need it for load, even though we have plans showing for '99 and 2000, we use one year lag of data. So what is showing up is '98 and '99 studies data. And we took a look at the forced outage rates by -- weighted by machine and by company and did the same for the availability numbers.

In comparison of last year's forecast to this year's projections, what we see is the forced outage rates continue to come down throughout the study period, the top line being the year previous forecast, the bottom line being this year. Again, this is a megawatt-weighted forced outage rate. And because improvements are seen in this area, as well as improvements in the reserve margins, the need for the LOLP study was -- we felt was not as necessary for this year.

COMMISSIONER JACOBS: I have a question. I have read recently of maintenance -- that the turbines that are used in combined cycles have a higher maintenance frequency and, therefore, that could play out in the long-term in terms of their availability. Has that proved out or have you seen that proved out in the research that you have done?

MR. CURRIER: On the combined cycle or the CTs?

COMMISSIONER JACOBS: I would expect it to be the combined cycle.

MR. CURRIER: Combined cycle. What we have here is the historical factors for all the machines. And to the extent there are combined cycles in Florida, which there certainly is, that is rolled up into these numbers.

COMMISSIONER JACOBS: And that doesn't show up in your numbers?

MR. CURRIER: Not as a -- not as a real issue, a big issue as far as availability.

MR. BALLINGER: John, excuse me. This is Tom Ballinger again. While we are on this, would it be reasonable to assume that at least the three investor-owned utilities that are in FRCC, Tampa Electric, Florida Power & Light and Florida Power Corporation, they participate in the GPIF as part of the fuel clause. It is a reward/penalty mechanism that looks at availability of generating units. Would we see a similar increase, I guess, if you will, in availability targets in that arena as well for certain units?

MR. CURRIER: To the extent that a certain number of these units are in the GPIF target, I would agree with that. A lot of the availability is driven by the fact that we adding 11,000 megawatts of new CTs and combined cycle capacity through time. And those are fairly available machines. And, also, there is also some repowering projects going on over the next three or four years that is also helping to improve these availabilities that were not necessarily factored into last year's trend.

MR. BALLINGER: Okay. So these trends are -- I will call them purely projections, if you will.

MR. COURIER: In the pot.

MR. BALLINGER: Okay.

MR. CURRIER: Yes.

The next page is the availability of the overall EAS system of Florida, or for Peninsular Florida. And you see the availabilities are up somewhat from last year, approximately a half a percentage point across-the-board. And, again, this is a function of the new units coming on the system, as well as the repowering projects. We have one dip in '02, and that is by and large to three or four large maintenance requirements that year. St. Johns has got a maintenance requirement. I know Sanford 4 is coming on line and they are repowering. And Purdom 8, I think, is coming off for their first major maintenance requirement. So you have got that one dip for that particular year; but by and large the availabilities, overall, are up slightly from last year.

MR. HAFF: John, this is Michael Haff again. I was going to ask you a question about that dip and then that sudden increase in availability in 2003. And it occurs to me in hearing your reason why, you know, the maintenance outages, I guess, occur in 2002, those happen all the time. I mean, why won't you see fluctuation in other years out in the future as other large units come up and down? I mean, does it just happen to be that in 2002 that these large units are all down at the time of peak?

MR. CURRIER: I agree with you, Michael, they certainly do occur. I think it is just a function of the short-termness where we specifically know of dates of these maintenance requirements. If you get out to '06, '07, '08, it's a lot -- obviously, it's a lot more nebulous of when you will take these outages for what units and other things. For this particular plant we know specifically these particular units have certain requirements that were factored into the numbers.

MR. HAFF: So I guess it is just a matter of you knowing -- having more of a certainty of how long the outage may take and then, thus, that affects the availability factor, the number of days that that amount of megawatts is down. Is that what you are saying?

MR. CURRIER: That's correct, right.

MR. VILLAR: My name is Mario Villar, I'm with Florida Power & Light. I just wanted to clarify that the length of the outages is a significant component associated with the numbers that you see here, and particularly in the case of our Sanford units. They are out for a significant portion of the year due to the repowering project that is taking place, and it is not a typical maintenance type of outage.

The units will be out -- Unit 4, for example, will be out for about a nine-month period in 2002, and Unit 5 for about six months. So that affects the numbers significantly.

MR. HAFF: And this is after they are placed in service as repowered units, they will brought down for a long maintenance outage?

MR. VILLAR: This is the -- the outage that will take them into the repowering mode.

MR. HAFF: Okay.

MR. VILLAR: You take them out and then you put them in the repowering mode.

MR. HAFF: Okay.

COMMISSIONER JABER: What part of the year will those plants be out, do you know?

MR. VILLAR: I don't have the schedule in front of me, Commissioner. But they will be out during the peak -- at least one of them will be out for a portion of the time during the peak. I can check on that for you, if you need it.

MR. SIM: Steve Sim, Florida Power & Light. Our Sanford 4 unit will be out starting March of 2002 and will come back as a repowered unit in December of 2002. Sanford 5, likewise, comes out October of 2001 and comes back as a repowered unit in July of 2002. And our Fort Myers 1 and 2 units come out in September of 2001 and come back as a single repowered unit in June of 2002.

COMMISSIONER JABER: Well, let me ask you a question with respect to availability. Let's say that it just so happens in the year 2002 we have the hottest summer recorded in history, it beats this summer. How do we ensure that there is adequate availability in the year 2002 when we know now that there is a good chance that there will be a decrease in availability because of the planned improvements?

MR. CURRIER: Commissioner, I understand that the operating committee, the FRCC, addresses those issues and plans in coordination with all the utilities' schedules to ensure to the best possible that we are meeting our loads. And I know they meet regularly.

Plus the fact that our reserves are up to 19 to 20 percent that given year, and that will also help ensure that there is enough capacity available in the marketplace.

COMMISSIONER JABER: And that would also take into account the people that move to Florida every year and the new developments and the new businesses that come to the state every year?

MR. CURRIER: Yes. These reserve calculations include all the load growth year-by-year.

COMMISSIONER JABER: What is your estimated load growth -- I think we already saw that slide, but what is the percentage each year?

MR. CURRIER: Two. Demand is growing at about 2.4 percent, and customer growth is slightly above 2 percent.

COMMISSIONER JABER: Thank you.

MR. CURRIER: You're welcome.

I am going to transition into natural gas transportation availability. With the emphasis on new capacity coming in as natural gas machines, the FRCC felt the prudent value this year to take a look at the reliability of FGT and the potential for any other pipelines that may come into Florida, although we focused strictly on FGT this year, who is our incumbent pipeline into Florida.

What I would like to talk about is really three major areas: The expansion of FGT, the availability of gas to FGT, and then the availability of gas requirements for the 11,000 megawatts of new capacity over the next ten years.

FGT is in a number of expansions. They are now constructing Phase 4, which today we have about a million and a half MMBTU of capacity per day through Phase 4.

Phase 5 is scheduled to come in service in April of 2002 which will add another 400,000 to that number. And that will help with some of the repowering projects that are going on throughout the state.

Phase 6, if it goes on schedule, is planned to come in in April of 2003, and that hasn't been decided yet exactly how much new capacity will be added in that particular expansion. They expect to file with FERC for approval for that expansion the first quarter of '01.

To put it into context, Florida's gas usage is driven in large part by the generators in the State of Florida. In fact, 80 percent of all gas serves the electric generation market. Only 20 percent serves the LDCs, as well as some of the industrial loads. Today Florida uses approximately 1.2 million MMBTUs per day for generation purposes. By 2009 the expectation is it will be 2.6 million MMBTUs per day.

This graph shows the increase of capability on the FGT system through time, going back to the original pipeline put into service in 1959. And we show the five different phases of expansion here. The first phase came in '87, and then you can take a look at each phase as it has come in.

After Phase 6, and assuming it comes in service and assuming that we have one pipeline through '09, these subsequent phases are going to need to add about 800,000 more MMBTU of capacity in Florida. So whether that comes with a new pipe or it comes through FGT, that is the need to serve this new generation.

A few other quality points about FGT is -- let me first mention that the Gas Research Institute indicates that there is enough supply of gas for 15 more years in the lower 48. In the Gulf --

CHAIRMAN DEASON: Excuse me. Let me interrupt for just a second. You mentioned 800,000 after completion of Phase 6. I was looking at the letter from FGT that was attached to the 2000 reliability assessment, and they mentioned 845,000 million MMBTU per day. Is that your 800,000 or has that number changed? You were just rounding down?

MR. CURRIER: Yes, sir. And, actually, I should recharacterize that. That is after Phase 5.

CHAIRMAN DEASON: After Phase 5?

MR. CURRIER: Right. Phase 5 will be approximately 2.1 million in capacity and then they're shooting for 2.9 million, approximately, by '09.

CHAIRMAN DEASON: Okay. So the 845 is what is needed after Phase 5 is completed?

MR. CURRIER: Correct.

CHAIRMAN DEASON: For the 2009 time frame?

MR. CURRIER: Yes, sir.

CHAIRMAN DEASON: Okay. And what is the -- Phase 6, what is the incremental capacity associated with Phase 6?

MR. CURRIER: They haven't specified how much volume they expect to add in that phase, and I think they are going through the solicitation period now.

CHAIRMAN DEASON: Okay. Thank you.

MR. CURRIER: Uh-huh.

FGT is a 4,800-mile pipeline from South Texas through Florida. Well over 99 percent of it is below ground, submerged. And with that comment, it is a very reliable pipeline. Incidentally, Gulf of Mexico exploration is expected to go up from 5.1 million trillion cubic feet last year to almost 8.1 million trillion cubic feet by 2015, which certainly feeds right into the FGT system.

My last point is there is well over 40 interconnection points throughout the pipeline. They have access to gas from Canada throughout most of the United States, through major hubs throughout Texas and Louisiana and such. They actually can access three times the amount of gas than they can deliver through all their entry points.

COMMISSIONER JABER: Are you aware of any other gas pipeline projects and what schedule they are on?

MR. CURRIER: You know, there is two other proposed pipelines. And I believe both of them are going through the FERC approval process, but I'm not sure exactly where the status of those are. Anybody in the audience might know.

MR. HAFF: I was just going to say -- this is Michael Haff. Commissioner Jaber brings up a good point, and I was going to wait until you finished to bring this up, but all we have in this reliability assessment is what you have gotten from FGT. And you stated, there are at least two more, I guess, Buccaneer and Gulf Stream that we've heard have filed at FERC for certification for natural gas pipelines to the state. And I guess the assumption I have in looking at this reliability assessment is that FGT is planning to supply everybody, when, you know, other sources tell me that is not true. Now I am just wondering why there is no assessment of these other pipelines that appear to be real.

MR. CURRIER: Yes, Michael. I think that is true, there is the potential of two other pipelines. But we look at this as a very conservative view in the sense that if we end up with only one pipe during the study period, this is what this particular pipeline's suggested delivery for the marketplace is.

A second pipeline and even a third pipeline will actually even improve overall reliability and availability of gas in Florida, so it is more upside.

MR. HAFF: And what this letter says is that if those two pipelines never get built that FGT promises, I guess, if you will, that they are going to meet everyone's needs in Peninsular Florida. That is really what I get from this letter.

MR. CURRIER: That's true.

MR. HAFF: Okay.

COMMISSIONER JACOBS: Brief question.

MR. CURRIER: Yes, sir.

COMMISSIONER JACOBS: Most of these gas units will have backup fuel of oil or coal?

MR. CURRIER: Yes.

COMMISSIONER JACOBS: Oil.

MR. CURRIER: The lion's share of them have backup.

COMMISSIONER JACOBS: Is it anticipated that there will be on-site storage for most of that? That could wind up being an interesting phenomenon when you have spikes in both oil and gas markets going now that will have a pretty significant increase in both of those fuels in the state. Is there planning going on for that? Are there measures being considered as to how to cushion that shock as much as possible?

MR. CURRIER: For the cost of the fuel?

COMMISSIONER JACOBS: Correct.

MR. CURRIER: I would expect so. You know, we didn't study that at the FRCC. I would expect each utility's group is attempting to hedge all the costs they can and properly manage their fuel supply.

The oil composition is going down through time. And any new plant that is permitted has fairly onerous restrictions on how much oil it can use for your backup purposes.

COMMISSIONER JACOBS: Okay. Thank you.

MR. CURRIER: FGT has an excellent reliability record. There has only been two main line outages in 30 years. The first one was in 1967 that lasted 16 hours. That was when there was one pipe into Florida. Today there is two and three. And the one that occurred in '98 was a lightning strike at Station 15, which was an unprecedented situation. I know FGT has invested a significant amount of funds to help protect against that situation.

And concluding comments, FGT is well positioned for future pipeline expansions, if necessary, in Florida. And the FGT system affords an excellent opportunity to collect numerous reserves and bring an actual commodity into the Florida market. And, again, from South Texas all the way across the southeast.

I am going to switch back to the load and resource plan. One of the items that was on the agenda is to ask the FRCC to address how it is reporting merchant plants in its report. These three comments capture how the report captured merchants this year. And I will try to go through these. The uncommitted merchant plant capacity is not listed in the FRCC load and resource plan unless it is an existing plant such as Reliance Orlando -- the Reliance plant, Indian River.

Thank you, gentlemen.

Or ground has been broken. If a merchant has firm contract with an FRCC utility, but has not broken ground, the amount of contract is shown in the interchange section of the FRCC plan and is included in the reserve margin calculations. So, effectively, a PPA is tied to the obligation to serve of a utility. And the last comment is that capacity from a merchant plant that is not under firm contract with an FRCC utility is not included in the reserve margin calculations. So there is some noncommitted capacity out in the market that is just not included in the reserve calculations.

COMMISSIONER JABER: Can I ask you a general question about the effect of a possible retail deregulated market? Does your planning going forward post-2002 include the possibility of a deregulated market?

MR. CURRIER: The plan -- the answer to that is no. The plan is a function of reliability based on an obligation to serve arrangement that we know today.

COMMISSIONER JABER: Have you looked at other states and the effect that deregulation has had on planning and reliability and capacity? And if you have, then have we accounted for that effect in our planning?

MR. CURRIER: No, not to my knowledge has the FRCC reviewed retail access states and their planning criterias.

Have we, Ken, or --

MR. WILEY: No.

MR. CURRIER: No. I know the RWG certainly hasn't. And we could take that on as an item for next year to do something like that, report back.

COMMISSIONER JABER: Thanks.

MR. BALLINGER: John, this is Tom Ballinger. I have got a question on the merchant plants. I understand that the FRCC basically included plants that were under construction. Basically, it may not have a commitment, some CTs, possibly the Constellation plant. But that is not included in the reserve margin calculation anywhere, is it?

MR. CURRIER: If is uncommitted, it is not included in the reserve margin.

MR. BALLINGER: Okay. Would that plant show up anywhere in as-available energy?

MR. CURRIER: Yes. It has shown up as an as-available, noncommitted resource in the NUG section, if it is existing, that is.

MR. BALLINGER: And what page is that on the load and resource plan?

MR. CURRIER: Which plan are you specifically asking about, Tom?

MR. BALLINGER: Say the Constellation plant.

MR. CURRIER: Oh, that one I don't believe is in the report. I know Reliance Indian River is.

MR. BALLINGER: Well, that's what I'm trying to get to is what page shows those noncommitted NUGs? It's Page 24, I guess.

MR. CURRIER: 24, 25, and 26.

MR. BALLINGER: Okay. And 25 and 26 are planned ones that aren't actually in existence generating today, correct?

MR. CURRIER: Yes, planned and proposed.

MR. BALLINGER: Are most of these, if not all of them, additions to existing cogenerators, or are they brand new facilities, or do you know?

MR. CURRIER: These are existing facilities.

MR. BALLINGER: Okay. And it mainly reflects firm contracts expiring?

MR. CURRIER: That's correct.

MR. BALLINGER: Okay.

MR. CURRIER: And they would become noncommitted capacity at the end of their terms. The first one being in '01 in the Indian River plant.

MR. BALLINGER: Okay. So Constellation, who is building some CTs, presumably in Brevard County, is not in this list either.

MR. CURRIER: That's correct.

MR. BALLINGER: Okay. And I understand the FRCC does not want to put merchant plants in a reserve margin calculation, and I understand that philosophical debate. But did the FRCC do any analysis or search, if you will, of what is going on activity-wise in the merchant community or in the generation community of building as to what is feasible in the future, just to get a sense of what kind of activity is going on in the new generation market?

MR. CURRIER: No, it hasn't at this point done that type of study.

MR. BALLINGER: Okay. And I know we had a debate, if you will, or a few meetings with staff and the FRCC and this topic came up. And I understand the FRCC's reluctance to put it in a reserve margin calculation. But staff is trying to get a handle for what the real world looks like out there, what is going on in the generation market. Do you have any suggestions where we should go to get that type of information of what is going on?

MR. WILEY: This is Ken Wiley with the FRCC. We certainly haven't done any, as you call them -- what John called studies, but we certainly have been keeping abreast of what we think is out there.

And one of the forums that we utilized is the IPP's national association, I forget the acronym and the name, but they have a Website, and they have all kind of data about every merchant-type plant going on in the United States. So we continuously look at that.

And the thing that we find out that is difficult about this particular list is it's hard to differentiate between what has been announced and how firm is it. But at least we are aware of everything that has been announced, some of which is very firm, but we are not sure how to classify all of it. So we do keep our eye on it, Tom. We just don't know how to handle it yet.

MR. BALLINGER: Okay. And staff is struggling with this, too. We're not sure whether to look at whether somebody has applied for air permits or requested interconnection studies from the utility as a good indicator. And we were hoping that the FRCC would do this as a regional group to get a complete picture of the region, but I understand it is difficult to classify them.

MR. WILEY: This is something that is going on at the national level, as well. We are not isolated down here. And at our national organization, NERC, as we call it, there is an effort going on in one of their major subgroups to study reliability nationwide. And they are trying to put their arms around this to be able to quantify it or to at least be able to discuss it and analyze it properly. So we are certainly a part of that group and we're watching what is going on.

MR. BALLINGER: Okay. Thank you.

MR. CURRIER: In summary of the reliability assessment, planning reserve margins have increased compared to our '99 plan, both summer and winter. Our forced outage rates continue to improve throughout the fleet, throughout Peninsular Florida, and our generating unit availability continues to increase.

And the last comment is our gas supply and pipeline expansion is expected to be adequate with FGT, and to the extent there is a second or third pipe, it would even bolster the capability into Florida.

The results of our review indicate that Peninsular Florida electric system is reliable for the next ten years from a planning perspective.

Unless there is any questions, I --

MR. ELIAS: I've got one. This is Bob Elias with the Commission staff. This study assesses the adequacy of resources at the time of summer and winter peak, is that correct?

MR. CURRIER: The reserve margin does, yes.

MR. ELIAS: Reserve margin, okay. Now, at times of system peak you would expect the scheduled maintenance to be minimized?

MR. CURRIER: Yes, that's correct.

MR. ELIAS: In several instances in the last few years we have seen supply get extremely tight in the so-called shoulder months, April, October. And some Commissioners and the staff have expressed concern that while reserves might be adequate to meet times of system peak, given the expected forced outage rates, the reasonably foreseeable temperatures, and the scheduled maintenance that occurs at times other than system peak that reserves might not be adequate.

And my question is has the FRCC undertaken any analysis to assess the adequacy of reserve resources in the shoulder months, given the high temperatures, forced outage rates and the fact that a disproportionate percent of the capacity would be off-line for scheduled maintenance?

MR. CURRIER: Again, on the shoulder months and the day-to-day type planning, the operating committee of the FRCC addresses those issues. And it works to coordinate the maintenance scheduling across the state, as well as to assess the daily capability, you know, from an operating committee viewpoint. From a planning and a load and resource perspective, we are looking at it year-to-year, peak-to-peak and planning the overall system. And certainly by improving the reserve margins and improving the availabilities will help in all times of the year, including the maintenance season.

MR. ELIAS: And then my other question is how, if at all, does the FRCC see this reliability assessment process impacted by the announced plans to form a regional transmission organization for Peninsular Florida?

MR. CURRIER: That should be no impact.

MR. ELIAS: Henry, do you have anything else to add?

MR. SOUTHWICKE: No. I think that is all we can say right now. The impact if -- it is possible that some duties may shift around. But if we are doing our job right, nothing will fall through the crack.

MR. BALLINGER: Henry, let me follow on that a little bit. Right now the operating committee gets together with the utilities and basically coordinates maintenance for the shoulder months.

MR. SOUTHWICKE: Yes.

MR. BALLINGER: Is there a minimum threshold, say reserve margin, you look -- you try to shoot for in order -- you know, like you want to keep at least 15 percent in --

MR. SOUTHWICKE: Fifteen percent.

MR. BALLINGER: All right. So that is in the FRCC criteria?

MR. SOUTHWICKE: Yes, sir.

MR. BALLINGER: Okay. And the FRCC basically uses, right now, peer pressure, if you will, to coordinate amongst the utilities to work out to maintain that?

MR. SOUTHWICKE: And it works quite well, Tom.

MR. BALLINGER: Right. And you don't see that changing when it shifts to the RTO about scheduling maintenance and having an authority to shift maintenance or anything in that nature?

MR. SOUTHWICKE: I don't know that the shift to the RTO could cause that to happen, other things could.

MR. BALLINGER: Okay. As we get to a more competitive, the best generation market?

MR. SOUTHWICKE: That could conceivably occur, absolutely.

MR. BALLINGER: Okay. Thank you.

MR. HAFF: I have got one last question I just found that I was going to ask. And this gets more to the, I guess, the short-term when you do the summer and winter assessments for each season, I guess, for the upcoming peak. And you know what I'm talking about, right, where you do the summer assessment or the -- I guess you would be doing the winter assessment for the upcoming winter soon, for the upcoming peak. It lists the reserve margin, I guess, and the amount of maintenance down at that particular time. And one of the concerns we have is when there are firm sales going out-of-state or out of the peninsular at the time of these peaks, how recallable, generally, are those sales? I mean, if we were to have a sudden need for that power, how recallable is a firm sale out of Florida during a time of peak?

MR. CURRIER: Well, I think that's -- I would, you know, defer that to the other utilities that may be actually selling out-of-state during those periods of time. I'm not sure how curtailable or how recallable those are.

MR. HAFF: Does the FRCC have any position, or any guidance, or any criteria for the utilities for such sales during time of peak?

MR. SOUTHWICKE: Mike, the degree of the firmness would depend on the sale itself, the deal, and what kind of arrangements were made specifically for that deal, as any other deal. And it would be up to that individual utility that made that deal to do that.

MR. HAFF: But I guess what I'm asking is the FRCC doesn't have any criteria that would say, okay, X-number of megawatts has to be recallable in case we need it.

MR. SOUTHWICKE: Not in that respect, but every day, as I'm sure you are aware, through our security capacity emergency coordinator procedures, every day of the year we go through the drill of every utility submitting to the SCEC his daily expectations of his load and capacity for that day. And every utility is obligated to cover his requirements. And that includes all firm sales, whether they be out-of-state, in-state, native load. And they are all listed on that report.

CHAIRMAN DEASON: Let me ask a quick question. When you receive that information on a daily basis and there are sales that are going outside of the state, that particular utility still has a requirement to have a 15 percent reserve margin?

MR. SOUTHWICKE: At that time it is no longer 15. He has to be able to cover his operating reserves.

CHAIRMAN DEASON: Just to cover --

MR. SOUTHWICKE: When you get into down into real-time, daily basis -- the 15 is a planning number, long-term. The theory generally is if he has 15 long-term, he will be able to cover the short-term when it comes, and it generally works.

CHAIRMAN DEASON: So give me an example of how that works on a daily basis. The day before you get a report from Utility X that says my anticipated load is 10,000, and I have capacity of 11,000, and I am going to be exporting 1,000, so I'm fine.

MR. SOUTHWICKE: Well, you have to able to show that you have your properly assigned FRCC reserves. So you have to have more than just your perfect match, but the concept is correct. In the summertime that is actually done in the morning for the afternoon peak.

Did you want to add anything?

MR. WILEY: Yes. On a daily basis, as Henry put it, we are looking at are we going to have enough operating reserves over the peak today in order to cover the loss of the largest unit that is operating in the state today? And our interest at that point in time is not to ensure that every individual utility has exactly a certain amount of power. But our interest is in the aggregate form, do we have enough capacity to cover the loss of the largest unit over the peak hour? And that is what we are searching for.

And as a matter of fact, that particular daily analysis, which is what we look at, you know, it was a result of us working with the Commission back in 1991, I think it was, and this is actually a Commission's order that we follow in going through this daily capacity assessment look.

CHAIRMAN DEASON: Okay. What happens when you get all of that information and you do not have enough capacity to cover the event of the largest unit going off line?

MR. WILEY: At that point we would issue an alert in the state under the plan and that would cause a lot of things to kick in. One of them being statewide calls for conservation over the peak hours of that particular day and notifying emergency management people. The Commission staff is part of this notification process. So a lot of things kick in underneath this -- within this particular plan if we were to get down to that situation.

CHAIRMAN DEASON: And is there any provisions to recall energy that is scheduled to be sold outside of the state on that day?

MR. WILEY: That gets back to an individual utility's contractual commitment with the party that they are dealing with out-of-state. And if they are selling stuff that is recallable, I'm sure they will recall it. If their commitment doesn't allow them to recall it, then it won't be recalled.

CHAIRMAN DEASON: Okay.

COMMISSIONER JACOBS: Can I follow on that question? So you are assuming, then, once you issue your call, you are assuming that individual companies will exercise those options. Do you monitor that? Do you ensure that that load actually comes around?

MR. WILEY: Well, I guess when you say "ensure," that is kind of -- we are not quite in the business to ensure that someone is going to do that. What we do with this particular forum is spread this information to all of the market participants that are generating, so that if one of the companies that has lost some capacity needs to, they know where to go in the rest of the state as to who has some power available, and they get that from this particular forum. So this particular forum facilitates the person that is having the emergency being able to go out and locate the power.

COMMISSIONER JACOBS: Okay. Thank you.

MR. CURRIER: That concludes the FRCC report.

MR. HAFF: Are there any other questions for FRCC?

Mr. Moyle.

MR. MOYLE: I have just a quick couple of questions.

John Moyle on behalf of the Moyle, Flanigan law firm.

With respect to the natural gas pipeline issue, I guess the plan shows an increased reliance on natural gas on a going-forward basis, isn't that correct?

MR. CURRIER: That's correct.

MR. MOYLE: And with respect to reliability, would the State -- would the State's reliability be benefitted by a second natural gas pipeline in your opinion?

MR. CURRIER: Yes. In my opinion it would be, sure.

MR. MOYLE: And are you aware right now, are all the utilities planning on getting their natural gas from the FGT? Your report focused essentially on FGT and didn't -- I think as Commissioner Jaber recognized, didn't look at the other pipelines. But I presume that is because at this point you understand that all of the investor-owned utilities are planning on purchasing from FGT?

MR. CURRIER: It follows the same thing that we have on reporting merchant capacity. Unless it is an existing situation or it is under construction, we find it very challenging to put that in the load and resource report. Both of those pipelines, to my knowledge today, have not broken ground or are coming across the Gulf at this point to be included as part of the overall reliability of the State of Florida.

MR. MOYLE: Has the FGT's last phase, has that broken ground, do you know? Where are they in their process?

MR. WILEY: I would like to comment on that, John.

I think what John Currier has been trying to say is that we look at the existing gas supplier, FGT, and its expansion plan as kind of a worst-case scenario. That if nobody else builds a pipeline into Florida, can that existing pipeline company serve our needs? That is the only question that we are trying to answer. We feel that if any one or two additional companies were to get permitted and were to find customers in the peninsula, that could only add to the gas availability and reliability into the state. So that is the way that we view it.

And sometimes it comes across looking like we are out there, you know, favoring one or the other, and we certainly are not. We are looking at that as a worst-case scenario. Can we get gas into Florida in the aggregate to serve all of these new gas units that people say they want to build? And that is the only question that we are trying to answer.

And in regards to your question about a second pipeline, if one were to come in, would that add to the reliability? I think it would add to the reliability if it were interconnected, even on an emergency basis, at some key point in the existing Florida Gas Transmission pipeline. And I think that interconnection is something that is very advisable for this state. And this isn't the first time I have said that to many people here on the staff.

COMMISSIONER JABER: Do you use that worst-case scenario philosophy in calculating what the load should be, or -- in other words, do you think ten years going forward that we might have, especially with what has happened with the weather thus far, that we might have the worst summers and the worst winters; and, therefore, reserve margins should be increased just as a matter of course?

In other words, what is wrong with the worst-case scenario in all of your planning? Especially in light of we just approved an incentive program for various IOUs that would allow them, that encourages them to make -- be more active in making wholesale economy energy sales, recognizing that there is a cost to having that reserve margin available. So what is the risk and what is the fear in having excess reserve margin?

MR. WILEY: Well, on the issue of load

forecasting, when Leo Green wants to talk about that -- he's in the audience. He would be the person to really answer your question there.

But I believe that the move that we made from 15 percent to the 20 percent IOU settlement that was made, I think that -- that begins approaching your worst-case scenario concept by adding that additional reserve margin in the state. And I think that you have bought a lot more in heading towards the worst-case scenario. And as we all know, if you continue to add more, it is going to cost more money. And I think the economics and the risk of not having enough versus the cost of having enough is something that has to be continuously evaluated by the individual utilities and this Commission. And it is not a simple issue.

COMMISSIONER JABER: But if we have just allowed a mechanism for the utility to recover the risk associated with having excess reserve margin, then what is the worst thing that can happen by increasing a reserve margin to 25 percent in the next ten years?

MR. WILEY: I think I will defer that to the utilities, because I'm not that familiar with your case.

CHAIRMAN DEASON: I have a follow-up question to a previous question. I understand that your 15 percent reserve margin is for long-term planning purposes, and that you do do a daily assessment and that daily assessment is based upon the -- in the event that the largest unit could be tripped off-line and you want it to cover that amount.

My question is at what point, as the system continues to grow, and we place more and more demands on the system, and we add more and more capacity on the system, at what point does that no longer -- is that no longer a good criterion to use for a daily assessment? It seems to me that the larger the system goes that there may be an eventuality that you could lose two units in any one day. And that that -- you know, the probability of maybe losing the two largest units maybe is -- the probability of that is so small that that is not a concern. But it seems like the more the system grows and the more units you have out there, the more likelihood that you could lose two units at one time. So how do you -- how do you make that assessment as to what is the correct criterion?

MR. SOUTHWICKE: That is a good question, and I can't -- I don't know the answer. We have discussed it, and we have voiced -- traditionally, for a long time at least, used the single largest unit, and it has worked well for us, and I think it is still working for us. I think our experience shows that.

CHAIRMAN DEASON: Well, you know, years and years and years ago the largest unit might have been -- I'm just throwing out a number, and I don't know. It might have been 2 percent of all capacity in the state. Now that largest unit might be just 1 percent of all the capacity you have in the state.

MR. SOUTHWICKE: And that works to our advantage. As the state -- as the load grows, the largest units have not been growing, as you say, over the years and that actually works to our advantage. Losing the largest unit is not as big a deal as it used to be.

CHAIRMAN DEASON: Because you have got more diversity out there. You've got more plants in various locations. And I understand that when you do a loss of load probability analysis, that actually -- in fact, the more plants that you have out there at various locations actually helps in that analysis.

MR. SOUTHWICKE: That's correct.

CHAIRMAN DEASON: But I guess my question is the more plants you have out there, the more physical plants, the higher the probability that you could lose two at one time as opposed to just one.

MR. SOUTHWICKE: You are correct, and I agree with you. The day will come when we'll need to change.

MR. WILEY: Well, I would like to embellish on that, if I could. This is Ken Wiley again.

What Henry was saying is absolutely correct for the daily capacity assessment, but that is not our normal practice every day and every hour of every day. Our practice is, is that we will have operating reserves available every hour to cover the loss of the largest unit, and we must have -- make available within 20 minutes after the loss of that largest unit enough capability reserve to handle the loss of the next largest unit in the state. So that is our daily, hourly operating practice. Now, when we get into tight hot days or emergency days, that's when this capacity emergency plan that we have been discussing comes into effect at that point.

CHAIRMAN DEASON: Okay. So you do have -- there is a 20-minute -- you have to be able -- in the event that the largest unit is tripped off-line, you have to be able within 20 minutes to still have enough capacity in case another unit is tripped off-line. Is that correct?

MR. WILEY: That is our operating reserve requirement in this state.

CHAIRMAN DEASON: Okay. Thank you.

COMMISSIONER JACOBS: You referenced earlier in your discussion about the planning that's has been done regarding the shoulder months. Are the plans you just described with regard to the loss of load at peak, are they encompassed in your planning for those shoulder months? Is there any additional planning that is necessary in the event where you have -- you may have significant numbers of plants that are off-line? Is there any additional planning that is called for there?

MR. SOUTHWICKE: In the shoulder months, the operating committee routinely looks ahead through every week of the year, and the requirement there is a full 15 percent reserve, looking ahead on a planning basis. And if they see a problem with that, then they go back to the utilities and we reconfigure our outage schedules.

CHAIRMAN DEASON: I see.

MR. SOUTHWICKE: Along with that we have agreements, I don't remember the exact dates, but we have agreements that we won't take major units out after, I think it is December 15th, and won't bring them down until after March -- I've forgotten the exact dates. But we have certain requirements to account for the load swings. But we still look at each week, week-by-week, and look at the generation schedule to be available and compare it with the load forecast on a weekly basis.

COMMISSIONER JACOBS: I have one additional question. I'm looking at -- in your load and resource plan, it is the summary of capacity demand and reserve margin table. And specifically I am interested in the data indicating the reserve margin without exercising load management and interruptible.

COMMISSIONER JABER: What page is that?

COMMISSIONER JACOBS: I'm sorry. This is the section -- the tab on generating facilities.

MR. HAFF: Page 19.

COMMISSIONER JACOBS: And it is Page 19.

Now, this data does align with your statement that load management is staying pretty level over time. The thing that interests me is it seems to still make up a significant portion of the total reserve margin, close to half in many instances.

MR. CURRIER: That's correct, yes.

COMMISSIONER JACOBS: And so that would seem to say that you don't anticipate any major trends in the subscribership to load management programs.

MR. CURRIER: Yes. A couple of reasons for that. One is the programs are fairly well penetrated in the marketplace. They have been out for 20 years now for many of them. And, secondly, the cost or the incremental marginal value for the load management programs are tending to go down as capacity costs continue to go down.

COMMISSIONER JACOBS: Okay. There are two circumstances that I thought of that might warrant consideration here. One, of course, is that for many years there had not been a great incidence of interruptions on those, and we have seen some of that recently. That could impact future trends. The other would be the emergence of some competition. I would think that customers who are buying on these schedules are going to be prime targets for some of these other -- for newer companies coming in. Do you see those having any particular impact?

MR. CURRIER: A couple of comments. First of all, if you look on that same chart, if you look at Column 8, you will see that there is a 7 percent capacity margin.

COMMISSIONER JACOBS: Right.

MR. CURRIER: And that is going to increase significantly next year to 11 percent. That is almost a doubling effect. So we would expect, at least on paper, that the amount of load management operations and interruptions should come down because of that reason alone.

Now, as far as our retail world, I think there is -- various strategies will get played out as far as how people will market to the interruptible customers, how they will market to the firm customers. And it is too early, I think, in even the other markets to tell exactly how some of those strategies will play.

COMMISSIONER JACOBS: Okay. Thank you.

MR. HAFF: Are there any more questions for FRCC?

Thank you, gentlemen.

Now we are going to go ahead and if there are any -- well, I guess there will be presentations from the investor-owned utilities on your ten-year site plans. And we will start with Florida Power and Light.

CHAIRMAN DEASON: Before we do that, we're going to take a ten-minute break.

(Recess.)

CHAIRMAN DEASON: If I could have everyone's attention, we'll call the workshop back to order and ask that you take your places. And just so that everyone is aware, the Commissioners have lunch in front of them. And so our intention is to -- we are going to eat lunch on the bench. And so -- really, in all seriousness, we are going to try to work through lunch and maybe finish the workshop without having to take a lunch break. But that depends on the length of the presentations. Not that I am pressuring you, but just be advised. But we are going to try to work through lunch and see if we can conclude at a reasonable time, early afternoon.

Staff.

MR. HAFF: First on our list of utilities is

Florida Power and Light company, and we will hear a brief presentation from them.

MR. VILLAR: Good morning, Commissioners. My name is Mario Villar. I'm Manager of Resource Planning for Florida Power and Light Company. And I will try to be brief on the presentation.

I'm going to touch on the salient points of our 2000 plan. Let me see if I can change the -- oops, wrong way. I am going to cover the resource additions we have on our reliability criteria and what the results have been on those two fronts.

The 2000 FPL site plan covers significant new additions to our -- to our plan over the 1999 and 1998 plans. We are roughly talking about an additional 1200 megawatts of capacity over the plan that we submitted in 1999, for approximately 4500 megawatts of new generation being added for new resources.

The summary that you see there, the breakdown for the period 2000 to 2009 consists of some changes to our existing facilities, some changes to the power purchases that we have with the cogenerators, small power producers, some of those contracts are phasing out. The repowering of our units and new generating unit additions that we have in our plan.

I realize this is impossible to read for those of you in the back, but this covers in more detail the 4500 megawatts that I discussed in the prior slide. In essence, the major additions to the plan will occur in the year 2001, where we are adding two new combustion turbines to our Martin site, and we are also undertaking the repowering of our Fort Myers facility for an additional 894 megawatts.

In 2002 we have the completion of the repowering project in Fort Myers. And also the repowering of the Sanford facilities, both Units 4 and 5, which will be taking place during that time period. Those result in incremental additions for each of the Sanford units in 2002 of 567 megawatts. And then, again, the second phase of Sanford which is completed in 2003 for Unit Number 4 also results in an incremental addition of 566 megawatts.

The number you see there, the 957 is because in the 2002 time frame we backed out the steam turbine for refurbishing, so we are bringing back that capacity in the year 2003. So that reflects the total megawatts for the repowered facility. We are also adding two combustion turbines in 2003 at our Fort Myers site for 298 megawatts.

And then the next major change in the plan is the addition of combined cycle facilities starting in

2006, and there is one unit being added in each one of those years.

CHAIRMAN DEASON: When do you anticipate the first -- the initial phase of the Fort Myers repowering? When do you believe that will be on line?

MR. VILLAR: Fort Myers repowering will be on line -- the first phase will be on line for the summer peak. These numbers here represent summer peak conditions.

CHAIRMAN DEASON: So it will be available for the summer of 2001?

MR. VILLAR: That is correct. It will definitely be in for the summer peak.

The next item that I wanted to highlight for you was FPL's new DSM goals. The Commission approved goals for FPL in 1999, and those goals are reflected in our plans. These are the numbers that FPL has approved for its new DSM goals as a result of the 1999 docket. By way of comparison, we did exceed our DSM goals for 1999 by about 225 megawatts.

At FPL we use two reliability criteria for measuring how our system is doing. We use a probabilistic methodology, which is a loss of load probability analysis, and a deterministic one, which is a reserve margin analysis, both of which are equally important. They measure different things.

We have the standards shown there under the second bullet for LOLP. It's a standard of 1/10th of a day per year, one day in ten years. That is the generally accepted standard.

And reserve margins, our traditional numbers have been about 15 percent minimum for both summer and winter. In 1999 we voluntarily adopted a 20 percent reserve margin to be effective by the summer of 2004, and that new 20 percent reserve margin number is included in our plan at this point.

The results of the generating capacity additions and DSM efforts that we have included in the 2000 to 2009 time frame are shown here. They definitely meet the LOLP standard by a significant margin; we beat it.

And the reserve margins that we have planned for both summer and winter are shown in the columns. As you can see, we exceed the 20 percent reserve margin starting in 2004 with a comfortable margin at this stage.

So based on the review of the plan and the generating capacity additions, the conclusion is that our system is projected to be very reliable, both from the reserve margin and the loss of load probability basis.

That concludes my presentation.

MR. BALLINGER: Mario, Tom Ballinger with staff. Was the driving factor in unit additions reserve margin or LOLP?

MR. VILLAR: At this point it is reserve margin, Tom.

MR. BALLINGER: Okay.

MR. HAFF: This is Michael Haff from the Commission staff. And I have got a few questions related to the request for supplemental data we sent regarding interconnection studies that may have been requested of FPL. Are you familiar with that?

MR. VILLAR: I am aware there was one. We do have some people in the audience that can expand on that if we need to.

MR. HAFF: Okay. I will go through a few questions here. We asked for some information on people who have approached FPL and requested an interconnection study, be it merchant, another utility, or whatever, and FPL has requested confidential status of that information. Are you aware that we are currently coordinating with FPL to review these documents?

MR. VILLAR: I am aware of that fact, Mike. But it may be better if we have somebody else address that issue. That is over in the transmission area, and I am generally sort of insulated from that, other than a general understanding of how that works.

MR. HAFF: Is there someone here that might be able to answer these?

MR. VILLAR: Yes, Mr. Tom Sanders is in the audience, and he can come up and --

MR. HAFF: It will be brief.

MR. GUYTON: Is it a question about the confidentiality or questions about the documents themselves?

CHAIRMAN DEASON: Charlie, you need to get to a microphone.

MR. HAFF: I mean, we are not going to divulge anything. I haven't seen the documents. It is just some general questions about this process, I guess.

Who are you?

MR. SANDERS: We're on. Tom Sanders.

MR. HAFF: Okay.

MR. SANDERS: Tom Sanders, Transmission Business Manager for Florida Power and Light.

MR. HAFF: Okay. You are familiar with our supplemental data request and the ten-year site plan regarding the transmission questions?

MR. SANDERS: That's right.

MR. HAFF: Okay. This is something I handed out to the Commissioners. I apologize for not Bate-stamping it, about -- it was your response to Question Number 13, where we asked for each of the entities that asked for a study to give us information on the size, location, the date the study was completed. Do you remember that table that you provided us? It looks like that.

MR. SANDERS: Right. That is our queue that is posted on our Oasis site.

MR. HAFF: There is quite a few here. It goes for two pages. But could you tell me which, if any, of these generation additions are FPL or FPL-affiliated resources?

MR. SANDERS: We really prefer not to identify at this time which resources are identified with which company.

COMMISSIONER JABER: You prefer not to or are there confidentiality concerns that you have?

MR. SANDERS: We have some confidentiality concerns with all the entities that we are dealing with. And we have tried to treat FPL on an equal basis in terms of how we are handling them in the interconnection procedures.

COMMISSIONER JABER: Because you are going through some sort of negotiations?

MR. SANDERS: We have agreed in our study agreements with the entities that we will retain the data as confidential. And a number of them have expressed interest in keeping at least the parent company's name confidential at this time. We have provided staff with a list of the generating entities with which we have been negotiating with. Some are identified with the parent company, some are not. But those are essentially the names that we have been using in our study agreements with the entities.

MR. BALLINGER: Commissioner Jaber, staff got that this morning. And, really, all we wanted to point out is FPL has requested confidentiality status of these documents, and that's per their agreement with their transmission customers. Staff has been trying to coordinate the work to view them, and there are some problems with do we need a nondisclosure agreement or not, and these types of things, and we're working them out.

Really, what staff is trying to get to is, again, answering that merchant question: What does the real world look like? We are trying to get a handle on what facilities or out there and what stages, and do they look like they are going to come to fruition. So that's really the information we are trying to gather from this. It's really -- we don't need to have a debate about it today. I think staff is working on it to get to it.

We just wanted to bring to light some slightly different treatment. FPL has requested confidential treatment. TECO gave us everything we asked for, for various reasons. But we are basically trying to treat everybody the same to get what is really going on out there.

COMMISSIONER JABER: So why are you bringing it to -- are you having any trouble getting information from FP&L?

MR. BALLINGER: No. We are struggling a bit. And I guess the only thing we wanted to bring to your attention today is: Are any of these FPL or FPL-affiliate plants, or are they all nonaffiliate customers; and, two, why the confidential treatment versus some utilities not doing confidential treatment?

MR. GUYTON: I can address the confidentiality concern, Commissioner, as we have addressed with staff. First off, we've said we will make all of these documents available for staff's review, and we just have not been able to get together with staff for their review. So there is no question that there will be access, complete access, to all the documents.

In some instances where study agreements have been signed, there are confidentiality provisions in those study agreements that information provided pursuant to the study agreement will be treated by the parties as confidential. That is primarily to protect the interest of the people that are seeking interconnection, and they don't want to disclose information that is project-sensitive about their projects, particularly in the early point in their development.

Because staff was a bit reluctant to sign a nondisclosure agreement to free the access to the documents up so we could avoid your confidentiality rule and all the onerous requirements associated with that, we went back to the various interconnection parties and asked them would they waive confidentiality, and all but a couple have. And to those there will be no problem with confidentiality. As to those, we are still trying to get a nondisclosure agreement so that none of us have to bear the cost associated with going through and filing the various requirements at the Commission here. That is where it stands. I can't address the other utilities. I can only address FPL.

MR. BALLINGER: Staff is fine. I don't think we have any other questions about this. We just wanted to bring it to your attention.

CHAIRMAN DEASON: I have a quick question, and I don't know who to direct it to, and maybe neither of you are the correct entity. But has FP&L had any customers or vendors approach you about trying to facilitate an interconnection of a microturbine? Are you aware of any?

MR. SANDERS: Not that I am aware of. A microturbine?

CHAIRMAN DEASON: Yes.

MR. SANDERS: Is there a better definition for that, maybe?

CHAIRMAN DEASON: Well, it is kind of a self-generation for a small to intermediate size commercial customer. It is kind of on the magnitude of fuel cells, but larger and maybe a little bit different technology. Are you aware of any?

MR. VILLAR: Commissioner, in general terms, we do get requests from some customers at various points in time to interconnect with FPL perhaps on a qualifying facility basis. We send them a package of information. But generally when they come in to us they don't disclose what type of facility they may be looking at. So there may have been some that contacted us; we are just not aware of whether they have been microturbines or not.

CHAIRMAN DEASON: Okay. Do you have a -- is there like a standard interconnection agreement that you require folks to comply with, or is it on a case-by-case basis?

MR. VILLAR: The interconnection agreement is in Mr. Sanders' area. They generally do the contacting with us first because of the power purchase, the QF-type contact.

CHAIRMAN DEASON: Okay. Maybe it is too early yet, but I think it is coming. Thank you.

MR. ELIAS: Mr. Villar, this is Bob Elias on behalf of the Commission staff.

We have seen significant, at least in the short-term, price increases for natural gas, in particular reflected in FPL's filing in the fuel docket. And I noticed from the resource expansion plan that virtually every unit in there was fueled by natural gas. And my question is given the recent price increases shown in natural gas, has FPL changed, at least informally, its expansion plan? Do you see different fuel -- different fuels firing some of the capacity additions that are reflected in this year's plan?

MR. VILLAR: We have not changed the plan. We are -- on a contact basis we are looking at different factors that may effect what the ultimate plan may look like on a yearly basis, and we do assess that regularly. But, first, we don't expect the large price increases that we have had to be sustained on a long-term basis. But if that were the case, we would look at all the available options and evaluate them on an economic basis and make a decision accordingly.

MR. ELIAS: Okay. Well, let me ask a follow-up question, then. Is it fair to say that based on the scenarios that you see, that natural gas is a clear favorite, or was it a close call as far as some of these resource additions?

MR. VILLAR: Natural gas was a clear favorite based on the results of the plan that we have.

MR. ELIAS: Thank you.

CHAIRMAN DEASON: I guess that is all the questions.

MR. HAFF: Are there any more questions for FPL?

Mario, I would just ask if I could get a copy of your slides, I would appreciate it. And for any of the other utilities that are giving a presentation, I would appreciate it if I could get a copy of your slides on paper.

MR. VILLAR: We will get you some.

MR. HAFF: Thank you.

MR. VILLAR: Thank you.

MR. HAFF: Next up is Florida Power Corporation.

MR. CRISP: Good morning, Commissioners and staff. My name is Ben Crisp. I'm Director of Integrated Resource Planning and Forecasting for Florida Power Corporation, and I'm here to provide Florida Power's overview of the ten-year site plan for the year 2000.

I'd like to start off with a quick review of our reliability criteria that we utilize. FPC currently uses reliability criteria of 15 percent reserve margin. It is a minimum reserve margin; .1 loss of load probability in days per year. And in the generic reserve margin docket, FPC agreed to increase its reserve margin criterion to a minimum of 20 percent. Now, FPC will implement its 20 percent reserve margin criterion in the winter peaking period of 2003 and 2004.

This chart gives an overview of FPC's seasonal peak demands for the years 1990 through 1999. You see the lines that depict the actual summer demand and the dotted line depicts the summer total demand.

CHAIRMAN DEASON: What is the reduction in 2003 from the previous years?

MR. CRISP: The reductions in 2002 and 2003 are contracts, wholesale contracts, that are expiring and those are peaking contracts.

MR. HAFF: Are they with FMPA or Seminole?

MR. CRISP: They are with Seminole.

MR. HAFF: Okay.

MR. CRISP: FPC includes the recent FPSC established DSM goals for the future years of 2000 through 2009 in the plan. The plan captures the transition to increase supply-side reserves. As you can see in this bar graph, what we want to show you is the increase in percentage of total reserves of our supply-side contribution. The supply-side contribution is in the magenta color, the bottom part, and the DSM reserves contribution is in the upper part.

So you can see as we -- as we add additional supply-side reserves in 2000/2001 out through the '03/'04 time period, we increase our overall supply-side reserve contribution to our reserve mix.

MR. BALLINGER: John, excuse me. This is Tom Ballinger. Do you have a similar slide for the summer season?

MR. CRISP: Let's see. Tom, I don't have a similar slide for summer, but I can get that for you.

MR. BALLINGER: Okay.

MR. CRISP: This slide shows our generation addition summary for the 2000 ten-year site plan. Intercession City, this project is moving toward completion. Units will be on line in December of 2000. There are three units, combustion turbines. Each unit is approximately 94 megawatts, winter rating, for a total of 282 megawatts of addition in December of 2000.

And then for the remainder, Hines Units 2, 3, 4, and 5. Hines Unit 2 coming on line in November of 2003. And then units in 2005, 7 and 9, respectively. The Hines Unit 2 brings us up to the 20 percent reserve margin criterion, and then in the Units 3, 4, and 5 reflect additions to support customer growth.

This is a pictorial slide of additions and retirements. What you see -- let's see, right here on the zero line, anything beneath the zero line is a retirement. So out in '03 and '04, you see a retirement; '05 and '06 you see a retirement; and in '06 and '07 you see retirements. These total approximately 400 megawatts of units, and those are primarily oil-driven units. There is some gas in there, but the units have been on the retirement plan for quite some time. You see the additions in '99/'00, '00/'01 and '01/'02, those are turbine upgrades. The small blocks with the addition of Intercession City in '00 and '01. And then you see the combined cycle additions in '03, '05, '07 and '09.

MR. HAFF: This is Michael Haff, again, with the staff. Which Crystal River Units are getting those upgrades? Are they coal or nuclear?

MR. CHRIS: They are coal plants.

MR. HAFF: Okay.

MR. CRISP: Coal turbine upgrades.

This is my final slide. It shows our projected reserve margin summary for the winter peak and the summer peaking periods. You see the increases up to achieving the 20 percent reserve margin criterion by 2004, and then maintaining reserves above the 20 percent reserve margin criterion beyond.

In summary, FPC is projected to be a very reliable system. And this concludes our presentation.

MR. BALLINGER: I have one question, John. In the reserve margin docket, FPC and the other two IOUs agreed to a 20 percent reserve by the summer of 2004, and now FPC has accelerated that to the winter of 2003/'04. Can you give a brief explanation why you felt the need to accelerate that criterion up?

MR. CRISP: Certainly. This is a two-point answer to a one-point question. The first part, as far as the 15 percent reserve margin and the reserve margin docket, FPC believes that each individual utility should have the responsibility for planning and developing and fitting the appropriate reserve margin criterion to that utility. That is what we were arguing in the reserve margin docket.

As far as moving ahead to achieve the winter peak of 2003, ahead of the 2004 stipulated time frame, FPC believes that it is in the best interest of our customers to go ahead and bring on those additional supply-side reserves for the winter peaking period.

MR. HAFF: Are there any questions for Florida Power Corporation?

Okay. Thank you.

MR. CRISP: Thank you.

MR. HAFF: Our next utility is Gulf Power Company.

I just want to add there is a cordless microphone up there if you all prefer to stand up and use that, unless you want to just sit down and do the slides.

MR. POPE: Good morning. My name is Bill Pope with the Gulf Power Company, Coordinator of Bulk Power Planning. With me is Mike Marler of our forecasting area, and we're here to present Gulf Power Company's review of their ten-year site plan for the year 2000. I would like to turn it over to Mike now.

MR. MARLER: Our forecasting procedures utilized in this site plan are the same as we have used in the past. They are the same modeling techniques, end use modeling for the long-term models.

Our current projections are essentially the same as they were in last year's site plan. Historically, we have seen approximately a 2.2 percent growth in summer peak demand. In the forecast period last year's long-term growth was projected to be one and a half percent, this year we are looking at approximately 1.3 percent.

In the winter peak demand, historically, the growth rate has been 1.6 percent. This year's projections are essentially the same as last year, with a slight increase in the short-term, and that is due primarily to a delay in the implementation of one of our new DSM programs. Energy for load, also, is essentially the same, and most of these are driven by, essentially, the same outlook on population growth.

This shows the impact of our DSM programs. Without DSM historically our growth rate has been 2.2 percent. Compound average annual growth would be 2.5 percent without the impact of our DSM programs. Cumulative savings through 1999 have been 272 megawatts on summer peak. And by the end of the planning horizon in 2009, we project to have a total of 512 megawatts reduced.

Similarly on winter peak demand, without the DSM impacts, the growth rate would have been 1.8 percent, and that has been reduced to 1.6 percent due to our DSM programs. That is reflecting a total savings of 302 megawatts cumulative through 1999. And by 2009 we are expecting that to grow to 583 megawatts. The impact on net energy for load has been 565 gigawatt hours to date through 1999, and that will grow to 797 gigawatt hours by 2009.

MR. POPE: I'm putting up now the summary of our capacity additions and retirements over the planning horizon, and I would just like to state that Gulf Power Company plans its system in conjunction with the Southern Electric System, and it is comprised of Alabama Power, Georgia Power, Mississippi Power and Savannah Electric Power Company.

But Gulf Power Company does need to meet its own needs, and this is what is reflected in meeting Gulf Power Company's needs. In the year 2002 we plan to install Lansing Smith Unit Number 3, a 574-megawatt combined cycle. Beyond that point our plans show, as far as additions, participation in Southern System units, and that's because those additions are far enough out in the future that firm decisions haven't been made based on specific sites yet. The first addition will be in 2006. Then we have a retirement of our Lansing Smith A, combustion turbine, at the end of 2006. And then another system addition of 60 megawatts in the year 2007, and then a 30-megawatt participation in the year 2008.

MR. HAFF: Bill, this is Michael Haff. Are these Southern System units -- at this point in time they are just generic units?

MR. POPE: Yes, they are.

MR. HAFF: Okay.

CHAIRMAN DEASON: This is Gulf Power's share of those units?

MR. POPE: It would be only Gulf Power Company's share. This would be of a much larger unit.

This particular -- our last slide shows a summary of Gulf's installed capacity, its load obligation. And on the far right columns, first Gulf's projected reserve margin and then the Southern Electric System reserve margins for the planning horizon.

As you see, Smith 3 does a tremendous amount for Gulf's reserves in 2002. And beyond that point we stay fairly -- fairly high with the exception of the trailing years. But on the Southern Electric System basis, which we plan in conjunction with our reserves stay at 15 percent, which is our target throughout time.

And that concludes Gulf's presentation. We would be glad to answer any questions.

MR. STALLCUP: This is Paul Stallcup with the Commission staff. I have a question for Mr. Marler. On Figure 2 you are showing a 0.9 percent growth rate in winter peak demand, and I think that is after conservation effects. Can you tell me how fast population is growing in your service territory and how that compares to the projections for demand?

MR. MARLER: Our population growth rate is projected to be approximately 1.5 percent throughout the '99 through 2000 time -- 2009 time period. And, basically, that would correlate -- I guess, the population growth would kind of be reflected in the summer peak demand growth without the DSM programs. And with the programs it is reduced to approximately .9 percent. Does that --

MR. STALLCUP: That answers my question. Thank you.

CHAIRMAN DEASON: Is the planning criteria for Southern 15 percent?

MR. POPE: That's correct. For the planning horizon, which is three years out and beyond, our target is 15 percent. It is very unlikely we could make decisions that would affect anything within that first three years. So our target is 15 percent for planning purposes.

CHAIRMAN DEASON: Okay. So why is it that Southern reserves are 13-1/2 percent?

MR. POPE: In the short or near term, there is less risk and there is nothing as far as planning we can do. We could make decisions to purchase things to sure up our reserves, so we don't hold a 15 percent target planning reserve margin except for the three years and out. That is why it is 13-1/2 percent in the near term, because there is less risk. There is more certainty in that time. And we can -- we plan to secure whatever we need to get to that 13-1/2 percent in those nearer years.

CHAIRMAN DEASON: And how much of that 13-1/2 percent is firm capacity as opposed to interruptible or some type of --

MR. POPE: I don't know the exact number, Commissioner Deason, but the majority of it is firm capacity. On the Southern Electric System, the vast majority is firm capacity or commitments for the purchase of firm capacity.

MR. HAFF: What I hear you saying about the Southern reserves being 13-1/2 percent for the first three years, that means next year when we are here doing this that it will shift a year.

MR. POPE: That's correct.

MR. HAFF: Okay. It's not that they are changing their criterion in any way, it is just that that short-term criterion is defined as three years and it will constantly shift out in time.

MR. POPE: That's correct.

MR. HAFF: Okay.

COMMISSIONER JABER: Does Southern Company serve in any deregulated states?

MR. POPE: The Southern Electric System, the Alabama, MIssissippi, Georgia, and Gulf, and Savannah?

COMMISSIONER JABER: Yes.

MR. POPE: No.

MR. HAFF: Are there any more questions for Gulf Power Company? Okay. Thank you.

Here is our chance to really fly, if you will. We have got the municipal utilities and co-ops coming up and -- oh, sorry. I forgot about Tampa Electric. You need to give a presentation.

MR. SMOTHERMAN: I'm Bill Smotherman with Tampa Electric Company, and I am here to give a presentation on our ten-year site plan. We have had some revisions to the plan, and I am going to focus a lot of my talk on those revisions.

The main revision to the plan has been a change in our Bayside repowering. Originally in the ten-year site plan we had filed for repowering Gannon Units 3 and 4 as well as Gannon Unit 5. Gannon Unit 5 represented Bayside 1. Gannon Units 3 and 4 represented Bayside 2.

Can you adjust that?

(Pause.)

The changes revolve around Bayside 2, where what we have done is we have actually revised the Bayside repowering on Bayside 2 to Gannon 6 instead of Gannon Units 3 and 4. This really consists of instead of using three CTs to be repowered in Gannon 3 and 4, we would use four CTs on Gannon Unit 6. That provides for additional capacity of about 250 megawatts, approximately, with similar heat rates.

The reasons why we went to this change, number one, Gannon 6 requires less complex valving and piping, merely because you have one steam turbine involved in the repowering versus two. And the physical location of Gannon 6 is more advantageous in the plant. Gannon 6 is the unit which is closer to an exterior wall. Gannon 3 and 4 are more interior to the plant; therefore, there is much more changes that you have to do, and you have to be more careful about actual construction associated with that unit. Gannon 3 and 4 would need to increase and decrease load together, which is a much more complex type of operation from a control perspective.

As we got through to the design of the units specifically, we found that we were in certain situations from a control perspective where we may have to shut down both of the combustion turbines in order to -- in order to -- actually both of the steam turbines in order to bring down a combustion turbine, one of the three combustion turbines. That kind of went counter to the reason why we chose 3 and 4 to begin with.

One of the main reasons why we chose 3 and 4 was additional reliability associated with repowering two steam turbines instead of one steam turbine. And seeing that we started to have this type of controls problem, it seemed to go counter to reliability, and may actually produce some worse reliability situations. So we felt Gannon 6 would provide a better situation there.

From a cost perspective, Gannon 6 is a newer steam turbine. It would require much less refurbishment than 3 and 4 will, so it will provide some cost savings.

And the controls perspective, as well, when we got into the detailed design of 3 and 4, we started seeing some increased costs associated with some of the controls that we were going to have to do on 3 and 4.

The repowering of Unit 6 will approximately provide the same heat rate and capacity as I mentioned before -- actually an increase in capacity but the same heat rate, as I mentioned before. And as I have also mentioned, obviously, there is less technical risk. It is an easier retrofit than 3 and 4 are. And from a cumulative present worth revenue requirement calculation, we are seeing about $14 million savings.

Lastly, but not leastly, the agreements that we have signed with the DEP and the EPA allow us to decide which units we are going to repower. They only specify that we do repower a specific number of megawatts. So there is no limitation on us or there is no changes that would be required associated with that agreement.

MR. HAFF: This is Michael Haff, again, with the staff. That next to the last bullet, the cumulative present worth savings of 14 million, I guess that accounts for the fact that instead of repowering old or less efficient units and keeping 6, as it were, you are doing the opposite. And I guess the savings include the fact that you would still have in your dispatch the existing Units 3 and 4 that are less efficient.

MR. SMOTHERMAN: Well, 3 and 4 from an expansion plan scenario will be put on long-term reserve standby, once that repowering is completed. For potential repowering in the future or also from an emergency standpoint, if we get short in a year and we want to run those units on gas.

MR. HAFF: But these savings include dispatch savings.

MR. SMOTHERMAN: They definitely include dispatch savings, and that is -- you are correct in the fact that the more megawatts combined cycle means less CT generation in the future and lower overall fuel costs.

MR. HAFF: Okay.

MR. SMOTHERMAN: From an availability standpoint, the Tampa Electric system is about 78 percent available. And with the addition of the Bayside units we should end up at the mid-80s, creeping up to the higher 80s as we go through time. This is merely driven by the fact that Gannon right now is a unit that has availabilities that run anywhere from the low 70s to the high 70s, depending on how much maintenance is done in a year. And once we have the Bayside units, those are more around the area of 90 percent available with those combined cycle units. So we are expecting a very great improvement in our overall system availability due to that.

You will notice that the system availability continues to increase over time. That is driven by the fact that we are adding combustion turbines after the addition of Bayside which, again, are in the 90s on their availability. So our overall system availability continues to increase.

From an emissions standpoint, you will notice that on Gannon Units 5 and 6 we are showing significantly more additions of NOX, CO and SO2 emissions, and there are very dramatic reductions associated with the repowering of 5 and 6. Those emissions are in the order of anywhere from 90 percent reductions to 80 percent reductions, depending on which one you are looking at there. But it is very obvious that there is some significant reasons why this was requested by the EPA and DEP.

From a reserve margin unit addition standpoint, the expansion plans are fairly similar. You will notice that we have a combustion turbine being added in 2002, followed by a CC, which represents Bayside 1 in 2003, and another CC, which represents Bayside 2 in 2004. You will notice that the CT in 2005 is absent in the new expansion plan versus the existing one. The reason for the absence is that CT actually become part of Bayside 2, because that CT is now one of the four CTs that is being used to repower Unit 6. So, essentially, that CT is being brought on a year earlier than it would have already been brought on. And the operation of that will be combined cycle operation instead of a simple cycle CT operation.

MR. HAFF: It's Michael Haff again.

Looking at this particular sheet, I guess, raises a question about this new expansion plan. TECO is not planning to file a revised ten-year site plan for this year, are they?

MR. SMOTHERMAN: No, we were not planning on that.

MR. HAFF: Is the new expansion plan just a result of the fact that your planning cycle for next year's ten-year site plan is already completed?

MR. SMOTHERMAN: Yes. And what we have done is we are aware of what impacts this will have, and we essentially went back and did a reliability calculation to determine what our expansion plan would be with the additional megawatts from Bayside to repowering. So we have not completed our planning cycle for 2001, although that is presently under review.

MR. HAFF: So the expansion plan I see in next year's ten-year site plan may or may not look like this new expansion plan.

MR. SMOTHERMAN: It will be very similar to it.

MR. HAFF: All right.

MR. SMOTHERMAN: From a winter megawatt capability standpoint, looking at 2001 and then going down to 2009, we are showing in this pie chart the different percentages that we are getting, capacity-wise, from our different resources. From an existing resource standpoint, you will notice that right now we have got about 9 percent purchases, about 23 percent DSM, and the remainder of that, about 68 percent, is made up of capacity. Most of that is coal-fired.

You will notice that in the winter of 2009 existing capacity is being reduced down to about 32 percent. Future is increasing to about 40 percent, and a large part of that being driven by the Bayside repowering. Demand is being reduced down to 20 percent, and purchases down to 7 percent.

COMMISSIONER JABER: Can I ask you to go back to the previous slide --

MR. SMOTHERMAN: Sure.

COMMISSIONER JABER: -- on system reliability? Based on what we have heard today, I think it is safe to assume that the population rate will increase and the demand rate will increase. So one should assume year 2007, year 2008, and 2009 the percentages will be higher with respect to demand.

MR. SMOTHERMAN: Uh-huh.

COMMISSIONER JABER: So why isn't it appropriate to assume that the reserve margins should be higher, much higher than 20 percent in keeping with the fact that demand and population growth will increase?

MR. SMOTHERMAN: Well,as demand and population growth increase, since those are percentages, the actual megawatts that Tampa Electric will be keeping on reserve will actually be increasing, as well, because these are calculated on a percentage basis. So, for example, in 2001 we may have -- that 19 to 20 percent may represent -- and I am just throwing out numbers here, may be 600-megawatts, not that that is the number. But by 2009 that is going to grow merely because we are calculating that on a reserve margin percentage basis. So that may be 700 or 900 megawatts. So it is increasing from an actual megawatt reserve standpoint. The percentage, since it is a percentage calculation, it will continue to grow from a megawatt perspective similar to how our load and our capacity will be growing.

COMMISSIONER JABER: And how do we know if that percentage, the incremental percentage increase or the difference, for example, 2001, 19 percent; 2007, 21 percent, a 2 percent increase. How do we know that is in keeping with the same level of increase of population and demand?

MR. SMOTHERMAN: Well, when we actually go through and make that calculation, we are incorporating the increase in demand. So, for example, demand is increasing on average about two and a half percent. We have got to keep our capacity increasing at that same percentage to maintain a 20 percent reserve. But to keep our capacity increasing at that same percentage means we actually have, physically, a greater number of megawatts.

So if you would like, I can provide you with an exhibit that would show you the actual megawatts of reserve through the years, but that number would increase every year as you go through the years.

COMMISSIONER JABER: And then to take that a step further, when you look at the percentage increases for demand and population growth you are basing that estimate on historical information?

MR. SMOTHERMAN: That's correct.

COMMISSIONER JABER: And that also assumes that the same facts and circumstances and economic atmosphere can exist in the state in the year 2008?

MR. SMOTHERMAN: Yes.

COMMISSIONER JABER: So you don't account for changes -- there is no cushion percentage or cushion factor that you take into account, then?

MR. SMOTHERMAN: There is a certain level of projection in the numbers from the standpoint, especially on the short-term where you are aware of particular areas that may be growing faster than what you have seen historically. For example, in Tampa's service area there are particular areas of growth that have shown greater growth than the overall average and that is taken into account. But over a long-term expansion plan where you are talking ten years, that becomes leveled out over time because that provides enough time between now and then to respond to any changes that you may see.

COMMISSIONER JABER: Perhaps I should have asked this of the FP&L person, but we have read a lot about the impact of technology and new Internet companies and ISP companies coming to the state. Do you believe that there could be a remarkable strain on reliability because of the technological revolution in the state?

MR. SMOTHERMAN: There is always a chance for higher load than what you have projected. And whether that's due to Internet technology or just due to a hotter than normal summer or a cooler than normal winter, that's always a possibility. But that is the reason why we maintain the reserves that we do. We feel that increasing to the 20 percent reserve provides that cushion to allow for that potential higher-than-expected load increase, either due to a forecast that was lower than what actually came in, or increased weather, or an outage of a unit. Because there is that uncertainty about what the future will actually bring.

I have also got a similar slide to the winter reserves for the summer reserves or megawatt reserves for 2000 and 2009 and how they are made up. From a summer perspective, we have got about 74 percent of our capacity represents our total megawatt makeup. About 15 percent is represented in demand reductions and about 10 percent or 11 percent in purchases.

In 2009 that is expected to increase to about 39 percent existing or reduced down to 39 percent existing. But the futures would increase to about 41. Again, driven by the Bayside repowering, 7 percent purchases and about 13 percent demand reduction.

On an energy basis our percent mix of fuels burned, right now we are projecting for 2000 that approximately 86 percent of our energy would come from coal. About 7-1/2 from Syngas which is from the Polk 1 IGCC unit. The remainder, 3.4 percent would be purchases and about 3 percent on oil. As we go into the future we would have a much more balanced portfolio. You'll notice that 54 percent will be coming from coal, about 36 percent from natural gas, again, driven by the Bayside repowering, about 7 percent from Syngas, 1 percent from oil and approximately 2-1/2 percent from purchases.

In summary, presently we are pursuing a more cost-effective repowering strategy with the Bayside units, and that accounts for the change on Bayside 2. We are also with the Bayside units realizing a great improvement in our overall availability of our system. We have firmed up natural gas transportation for the Bayside units and that will be on FGT.

And TECO, as you have seen in the reserve margin tables, is presently going to meet a 20 percent reserve margin from the years 2002 and beyond. TECO's ten-year site plan also provides a much more balanced fuel mix resulting in economic benefits and environmental benefits for our customers and the state as a whole.

MR. HAFF: Does anyone have questions for Tampa Electric Company about their ten-year site plan?

Okay. Thank you.

COMMISSIONER JABER: Mr. Chairman, if I could have someone from Florida Power and Light answer a question with respect to South Florida.

MR. VILLAR: Yes, Commissioner.

COMMISSIONER JABER: There has been the creation or at least the movement to create something called the Network Access Point in South Florida that is designed to bring new technology companies to that area. And I know you are the largest provider in the South Florida area. Have you taken into account in your planning the impact of technology and Internet into your area?

MR. VILLAR: Let me answer that in a very general way, and then I will turn it over to Dr. Green. Perhaps he can give you some more details if you need anything.

In this particular plan we do not have any of those proposals incorporated in the plan at this stage, but we are aware there are these proposals out there. To the extent that we feel they are materializing, we will be including the forecast of additional load into our plan as appropriate, as we do other forecasting techniques. And Mr. Green -- Dr. Green can get into that if you need some details.

DR. GREEN: My name is Leo Green at Florida Power and Light. Yes, there is a substantial amount of activity going on in Miami. And we are talking about 180 megawatts for next year, of 350 for the following year, and capping out at about 570 megawatts in 2003. The plans that we are developing currently will include on both sides, on the generation side and the capacity side, how we will address that additional load.

COMMISSIONER JABER: So the megawatts you gave me 180, 350, and 570 are the megawatts associated just with the power needed for Internet?

DR. GREEN: Just for the telecom loads.

CHAIRMAN DEASON: That is a lot of telephone calls.

MR. HAFF: Now we are going to jump into the municipal utilities. And we will go in order on the order of appearance here. If you have a presentation, feel free to give a brief one. If not, I guess come up and see if we have any questions for you. We will start with Florida Municipal Power Agency.

MR. CASEY: I am Rick Casey with FMPA, System Planning Manager.

I do have a few slides. But in the interest of time, I can simply answer questions or walk you through them if you would like. I will leave it up to you and your staff as to what you would like to do.

CHAIRMAN DEASON: I do not need to see your slides unless you feel compelled to show them.

MR. CASEY: No, sir, I don't.

CHAIRMAN DEASON: Staff.

MR. HAFF: I'm in agreement with you, obviously. I have read their plan --

(Laughter.)

I have read their plan, and I don't have any questions.

CHAIRMAN DEASON: You can show your slides, because I am eating lunch now.

MR. HAFF: Some of us aren't.

CHAIRMAN DEASON: You are trying to get the last word, aren't you?

MR. HAFF: Okay. Let's cut to the chase. Are there are any questions for FMPA? Okay.

This looks like a consent agenda. Thank you for making the trip. If you have copies of your slides I will be glad to take them.

Next up is Gainesville Regional Utilities.

MR. KAMHOOT: My name is Todd Kamhoot. That is Roger Westfall distributing a handout of ours. Which, like FMPA, I can either go through or merely make myself available to answer questions if you would like.

CHAIRMAN DEASON: Well, let me ask you this question. Is there anything that is out of the ordinary with your expansion plans from last year?

MR. KAMHOOT: No, there is not. We have a repowering in progress, a 50-megawatt steam unit that will -- it is underway. That unit will be taken off-line perhaps next week, and we expect the repowered combined cycle, 110 megawatts total, or 60-megawatt net increase to be on-line next spring. That is going as scheduled.

CHAIRMAN DEASON: Okay.

COMMISSIONER JACOBS: To what extent are your plans entailing purchases? I should ask you is there any increase of purchases anticipated in your planning?

MR. KAMHOOT: We have no firm purchases in our resource mix.

COMMISSIONER JACOBS: Okay.

CHAIRMAN DEASON: I'm looking at Page 7 of your handout, and it appears that you have -- you're projecting sufficient reserves based upon a 15 percent reserve margin, is that correct?

MR. KAMHOOT: That is correct. Beginning next summer through 2009, we expect to have at least 22 percent reserves through this planning horizon. And we plan to meet summer peak. We are a summer peak driven utility.

MR. HAFF: Are there any questions for Gainesville?

Okay. Thank you.

MR. KAMHOOT: Thank you.

MR. HAFF: Next on the agenda is JEA. And I suspect since you are building a brand new plant, you probably have a few slides to show us.

MR. BOND: My name is Chuck Bond, and I am Manager of Capacity Planning at JEA, and I have a few slides. But I will probably -- the one I wanted to go over the most was probably towards the back, which was a couple of modifications that we have in what we submitted and really where we are going toward from here.

On what we submitted in our ten-year site plan, we showed having three units at our Brandy Branch generating station come on in 2001. The first two were going to be in December, and then the third one was going to be in December of the following year.

And we ran into a little bit of a problem with trying to schedule an outage to do some of our work that we needed to do at Northside with our repowering project ahead of time, and an outage to do some transmission work where we are going to -- we have existing 230 lines come by Brandy Branch. We are going to terminate those in a new substation.

And we couldn't have all that -- the transmission lines and the outages done at the same time. So we ran into a little bit of a scheduling conflict. So we have moved the on-line date of two of our CTs at Brandy Branch Units 1 and 2 out until May. And that will result in this coming up winter we will have to buy 250-megawatts like we did last winter.

And we have the Energy Authority currently looking at that and seeking out proposals to buy this capacity. And with our position with the tie line on our interface, we shouldn't have any problem meeting that, but we don't have that under firm contract at this time.

We just kind of made some of these decisions about this about two months ago. So we have been trying to procure this capacity and time it when the market is at the right time to buy it, and go forward from there.

CHAIRMAN DEASON: There may be some people here interested in selling it to you.

MR. BOND: And now that we have our -- the Energy Authority is our marketing company, and they are out actively pursuing that. So we don't see an issue with that.

The other notes we have down there is on our repowering of Northside 1 and 2. We showed both of those in April of 2002. We are actually going to have Northside 2 -- it will be available in the February time frame, and then Unit 1 will come on second. It will be in the summer sometime, and we are not sure whether it will be before June or sometime in the June/July time frame. We are working on trying to consolidate our schedule for that.

And the other item that we showed differently is when we submitted our site plan, we showed a combined cycle conversion at Brandy Branch in 2003. And we put some kind of language in there that we really were doing that, because we didn't have a need until 2004. But we were showing it in the ten-year site plan because we were looking at bringing it in early and potentially increasing our reserve margin.

And when we started looking at that a little bit closer, we found that we really couldn't meet the scheduled time frame for all the need determination hearings and really meet that without doing some accelerated and spending a little bit more money to get that in. So we are now looking at June 2004 to bring that combined cycle plant on-line, which is when we had a real need to have it.

So those are a little bit of refinements to our plan that we had from what we showed in the submittal.

MR. HAFF: I guess for our benefit and the scheduling of need hearings, and so on and so forth, when do you expect to be filing a need application for that combined cycle conversion of Brandy Branch?

MR. BOND: I believe our schedule is in October, October/November.

MR. HAFF: Of this year?

MR. BOND: Correct.

MR. HAFF: Okay.

Are there any questions for JEA?

Okay. Thank you.

Next on our list is Kissimmee Utility Authority.

MR. MILLER: Good afternoon, Commissioners. My name is Robert Miller, and I am Manager of Bulk System Planning, Kissimmee Utility Authority.

MR. HAFF: You need to turn on the microphone.

MR. MILLER: Good afternoon. My name is Robert Miller, and I am manager of Bulk System Planning at Kissimmee Utilities Authority. I am prepared to answer any questions or make any comments that you want me to make.

CHAIRMAN DEASON: Has there been any significant change in this forecast or this plan from the presentation you made last year?

MR. MILLER: Not much change, no significant change. We are much further along with our Cane Island unit, which is scheduled to be commissioned in June this year, or 2001.

COMMISSIONER JACOBS: You area is seeing significant growth. Has that impacted your planning at all?

MR. MILLER: We have been seeing significant growth over the last couple of years. We have adjusted to that.

CHAIRMAN DEASON: I'm sorry. I'm just thumbing through your slides, and I see that there is a bullet point beside World Expo Center and projected load. Could you explain that?

MR. MILLER: Yes. This is a major 800-acre development that was proposed a couple of years ago. It was scheduled originally to be, to be on-line sometime this year, but it has been pushed back and pushed back. Currently it is reduced by 50 percent, and we are not quite sure whether it will come to fruition or not. But we have kept it in your plans and pushed it back appropriately. Currently, it is scheduled for -- it is phased, and it is currently scheduled to be -- construction is scheduled to start in 2001, but we have no further information on that.

CHAIRMAN DEASON: Thank you.

COMMISSIONER JABER: The slide right before the one that you are looking at that is entitled capacity balance, help me understand this chart. It looks like reserve margin beginning with 2007 is a negative.

COMMISSIONER JACOBS: It has a table that has reserve margins that are positive.

MR. HAFF: Commissioner, I could probably answer that, unless you want him to. I believe this table shows assuming no new unit additions, if they just keep their capacity as it is without adding new capacity. And what this would show is the timing of when they need to add more power.

COMMISSIONER JACOBS: There is a table that shows the expansion plan that is probably more to your question.

MR. HAFF: Yes, two pages later shows the one with unit additions.

MR. MILLER: Thanks, Mike.

Yes, it was as Mike said. That just shows what the reserve is with retirements. And the next page has expansion -- which has the expansion plan on top has the actual reserves.

COMMISSIONER JABER: So really in 2007 your reserve margin you estimate will be 35 percent?

MR. MILLER: 35 percent, yes.

COMMISSIONER JABER: So the chart I was looking at reflects what, then?

MR. MILLER: It was just a table that shows how the existing capacity diminishes over time without additions.

COMMISSIONER JABER: Thank you.

COMMISSIONER JACOBS: You cited your residential load management program and it seems to contribute a significant amount. Explain that to me, walk me through how that works.

MR. MILLER: I didn't hear the question.

COMMISSIONER JACOBS: Your Save program, the residential --

MR. MILLER: The Save program?

COMMISSIONER JACOBS: Yes. It seems to have a very positive effect on your --

MR. MILLER: Reserve margin.

COMMISSIONER JACOBS: -- reserve margin. What are the significant factors that contribute to that in the program, in the Save program?

MR. MILLER: Well, initially, we had a pretty healthy rebate, and it was a very popular program. What we have done in recent years, we have adjusted the rebate to be an economic rebate. But it has remained economic. It has remained a fairly popular program.

COMMISSIONER JACOBS: Okay. Thank you.

MR. HAFF: Are there any other questions for KUA?

Thank you, Mr. Miller.

Next up for presentation or questions is the City of Lakeland.

MR. ELWING: Good afternoon, Commissioners. I'm Paul Elwing representing Lakeland Electric. In the interest of brevity, I'll not go through every single slide, just stand ready to answer questions if you have any.

MR. HAFF: This is Michael Haff again. You may -- this may be a good opportunity to go over the last two slides, Pages 10 and 11, because Lakeland, to my understanding, is the only one over the next ten years of anybody in the state that is planning to build a coal plant. And you might want to give the Commissioners a heads up of that project and what is going on with that.

MR. ELWING: Okay. Yes. Right now in our planning analysis we are proposing to build a solid fuel unit to be in service in June of 2005, approximately 288 megawatts, pressurized fluidized bed technology, capable of burning petroleum, coke and/or coal.

Looking earlier in your slides you will see there is a -- let me get to the page here. On Page 9 of your packet there is an existing and future resource mix. And currently in the year 2000, Lakeland's resource mix is made up of approximately 59 percent gas and oil-fired units and 41 percent solid fuel.

Looking out to the future, we feel that we need to maintain a better balance of fuels, and so our proposal is to build another solid fuel unit in the 2005 time frame for the horizon year of this current planning cycle 2009. That would bring our solid fuel capability on an annual energy basis up to 56 percent, with gas and oil-fired units at 44 percent of our energy requirements. Going back to Slide 10 and then finishing out the horizon period with a combustion turbine in 2009 to meet our reserve margin requirements to cover growth.

MR. HAFF: In discussions with the staff that you have had with us, you have explained that adding this coal-fired unit is going to be -- is the most cost-effective option. And I would like for you to explain that a little bit further, because none of the other utilities share that opinion, at least for their system.

MR. ELWING: Okay. For us it is tied to what we believe the price of fuels is going to be in the future. Our fuel forecast is presented on Page 5 of the handout. We believe the future for solid fuels is going to be lower cost and stable fuel prices, whereas, natural gas is going to continue to escalate in much higher proportions. We have already seen this year natural gas prices have jumped significantly. As a matter of fact, they are higher currently today than what our forecast numbers are showing. And we just feel that that trend is going to continue well into the future.

And so when we do our analysis, and based on our cost of capital and our abilities in negotiating for fuels, et cetera, right now for us a solid fuel unit is coming in to be a least-cost option for us as compared to natural gas.

CHAIRMAN DEASON: Have you already pursued long-term coal contracts for this unit or is it too preliminary at this point?

MR. ELWING: We have approached suppliers and have begun getting commitments for fuel supply for the unit, but we have not actually signed any contracts. But we have been in contact with suppliers.

CHAIRMAN DEASON: And I assume you will be transporting this fuel by rail, is that correct, or how would you?

MR. ELWING: That is one possibility. We are also looking at some waterborne sources and then transloading in the Tampa area.

CHAIRMAN DEASON: When will you begin the permitting process for this unit?

MR. ELWING: We are hoping to bring a petition for need before this Commission towards the end of this year, probably in the November/December time frame that we would be filing with staff.

CHAIRMAN DEASON: And would that be -- that would be the first step before you begin the environmental permitting?

MR. ELWING: That is correct.

MR. HAFF: Have you -- I guess DEP is aware of your plans?

MR. ELWING: Yes, we --

MR. HAFF: I'm assuming you have talked to them about this.

MR. ELWING: Yes, we have already approached DEP and have had open discussions with them about the unit, about the technology, and what the anticipated emission rates would be from the unit. And at this point in time we have gotten no roadblocks or objections from DEP.

MR. HAFF: Have you gotten any feedback at all?

MR. ELWING: Not really. We have put out press notices locally and have gotten no responses. At least for our customers in our area, it is not an issue.

COMMISSIONER JACOBS: Are you anticipating incorporating emission technology on this plant?

MR. ELWING: Yes. This particular technology goes along with the Department of Energy's clean coal technology program. And so this would be one of the cleanest solid fuel-burning units in the United States.

COMMISSIONER JACOBS: I would be interested to have -- to have a presentation on that, maybe at Internal Affairs or something.

MR. ELWING: I don't have one with me, but --

COMMISSIONER JACOBS: No, I mean later at Internal Affairs or something.

MR. ELWING: -- we can prepare something for you.

CHAIRMAN DEASON: Will there be any cost sharing from the Department of Energy or is all that not available anymore?

MR. ELWING: The current technology that we are looking at would not qualify for the DOE clean coal technology program as we understand it. This is a slightly different technology and a different vendor, but the similarities are extremely close.

MR. HAFF: Are there any questions for the City of Lakeland? Okay. Thank you.

COMMISSIONER JACOBS: Oh, I'm sorry, I did have one question. In your table on reserve margins, this --

the winter of this year is fairly low. Are you undertaking any particular measures to address your reserve margins for this year, this winter?

MR. ELWING: Okay. The reserve margin, I believe, that you are referring to was the winter reserve margin for January of 2000, which has already passed, we did make it through this winter all right.

COMMISSIONER JACOBS: Okay. Thank you.

MR. HAFF: I apologize, that raises one more question. Last year's plan -- I mean, we didn't see this forecasted for what would have been the next winter. I don't recall the reserve margin being below 15 percent forecasted for this immediately past winter. What was the cause for this?

MR. ELWING: Okay. Originally, we had anticipated our McIntosh Unit 5 being commercial by January of this year. That has not taken place yet. That is the 501G, which is the first unit of its type. We are very near commercial stages at this point, and so it was not actually commercially available for January of 2000, and so that is reflected in the lower reserve margin.

MR. HAFF: Thank you.

COMMISSIONER JACOBS: And the figures -- the present figures for this winter anticipate that unit?

MR. ELWING: Yes, sir. We are anticipating that unit to be commercial by October. It is in final test and checkout stages. There is one remaining test that the manufacturer would like to go through. And barring any unforeseen circumstances the unit should be declared commercial in the October time frame. It has been up and running this summer in test mode.

MR. HAFF: Okay. Thank you, Mr. Elwing.

Next we will hear from or ask questions of the Orlando Utilities Commission.

MR. ROLLINS: Yes. I'm Myron Rollins with Black and Veatch. We helped OUC prepare its ten-year site plant. I have Matt Blankner with me. We have a presentation, but in the interest of time we will be glad to just answer questions.

MR. HAFF: Do you have any handouts?

MR. ROLLINS: We have one copy of the handout which I will give you to.

MR. HAFF: Okay. We will get it later.

CHAIRMAN DEASON: I have no questions. I have nothing in front of me to ask questions from.

MR. HAFF: I will ask is there any major change from last year's plan to this year's plan that we should be made aware of?

MR. ROLLINS: Yes, there is. Last year about this time they were in the final stages of completing negotiations of the sale of the Indian River steam units which got completed and sold to Reliant. So this year's plan includes the power purchase agreement from those plants. That power purchase agreement extends through October 1st of 2003, and has an option for a four-year extension. In their plan it appears that they can build a combined cycle unit to replace that capacity in the 2003 time frame for a lower cost.

MR. HAFF: I guess as a result of that combined cycle showing up in this year's plan that wasn't in last years plan, correct?

MR. ROLLINS: That's correct.

MR. HAFF: What time frame would we be looking for a need determination for this unit?

MR. ROLLINS: It is in the September, October, November time frame.

MR. HAFF: Of this year?

MR. ROLLINS: Of this year.

MR. HAFF: Boy, are we going to be busy.

Okay. Any questions for Orlando Utilities Commission?

Okay. Thank you.

Myron, I would like to get a copy of that handout if I could.

CHAIRMAN DEASON: Staff, how long do we have to process these need determinations, is it by statute?

MR. HAFF: I'm sorry?

CHAIRMAN DEASON: Is It by statute the time frame that we have to process these?

MR. HAFF: The statute, as I understand it, is more of when DEP has to get an order before the Governor and Cabinet. Our rules, in order to get a filing to DEP, an affirmative or negative determination of need, we have 90 days from the day it is filed to hold a hearing. And ultimately a Commission order has to be out within 135 days. A decision in 135 days. And those time lines assume that they file simultaneously with DEP and with us. So we are usually under a 90-day time frame to have a hearing from the date of the filing.

Next up is the City of Tallahassee.

MR. CLARK: Good afternoon, Commissioners. I am Paul Clark, Chief Planning Engineer for the City of Tallahassee.

You have before you a presentation that I did prepare for today. But, again, in the interest of time I can just field any questions.

CHAIRMAN DEASON: What do you think about the City of Lakeland's coal plant?

MR. CLARK: Well, being a former City of Lakeland employee myself, I might be a little bit prejudiced. I certainly understand and share some of the City of Lakeland's concerns about fuel diversity.

CHAIRMAN DEASON: Good answer.

MR. CLARK: Thank you.

COMMISSIONER JACOBS: Very diplomatic.

MR. HAFF: I've got a question, and, Commissioners, for your reference you can turn to the first two tables in the handout -- the memo I sent to you the other day. And this is information from Tallahassee's ten-year site plan.

And I know, Mr. Clark, you don't have this handout, but it's just the copy -- it's the reserve margins from your plan, summer and winter. And I am looking at a summer reserve margin in 2009 of 2 percent. I guess I'm just -- it looks like there is a needed unit out there somewhere in the future, and I'm just wondering if you could respond to that.

MR. CLARK: You are absolutely correct, Mike. We do anticipate the need for, I believe through the horizon year 2009, a total of just over 90 megawatts of additional power supply resources. We have not yet identified specific additions, as we stated in our plan document. We are looking at combinations of, to satisfy the short-term smaller needs, some peak season firm purchases. The larger long-term needs may be satisfied with a combination of multi-year firm purchases and/or capacity additions or enhancements.

MR. HAFF: I guess it is a practice for some of the utilities to, you know, put a generic CT or something in there. You know, obviously, it is a plan; it can change from year to year. Have you identified any combustion turbine or something that might be commercially feasible and somewhat cost-effective in your planning that you maybe could show as a unit in the out years?

MR. CLARK: We have done some preliminary analyses of our needs for the coming ten year and, actually, beyond period. As a matter of fact, some combustion turbine technologies do appear to hold some promise for us. We currently do not have any quick start generation capability. And as a result, we are required to carry all of our operating reserves as on-line or spinning reserves.

So we are looking to -- in addition to satisfying our additional capacity needs, maybe reap some benefits in terms of increased efficiency by replacing some of our older less efficient combustion turbines with newer units, but also being able to decrease the amount of generation that we have to keep on line to satisfy our operating reserve obligations.

MR. HAFF: Are these things you are considering something that may show up in next year's plan?

MR. CLARK: I certainly would expect them to.

MR. HAFF: This reserve margin concerns me.

MR. CLARK: I understand. And, again, we are still, I guess, recovering from the in-service of our latest generation addition, Purdom 8, which was declared commercial last month. I am a very new staffer to the City of Tallahassee. I started about six months ago. We are just gearing up for our first full-blown supply-side resource analysis after the advent of Purdom 8.

MR. HAFF: Okay.

CHAIRMAN DEASON: I have a question for you. I notice that one of your key input assumptions is transmission constraints, which I'm sure enters into every utility's plan. But is that a particular problem for the City of Tallahassee or not?

MR. CLARK: Yes, sir. We currently have, and hope to be able to maintain the ability to import power to replace the loss of our largest unit, which now basically are two units, both our Hopkins 2 and Purdom 8 units are about equal in size. And between the two of them they make up, basically, two-thirds of our power supply portfolio. This is critical to us in our minds as far as maintaining the reliability of our operation to be able to import to replace in light of one of those two contingencies.

If we were to look at firm purchases as far as satisfying our future need, that diminishes our ability to replace that power. And in the absence of some transmission improvements in the area, we feel like, at least for the time being, most of our future supply needs are going to have to be developed locally.

CHAIRMAN DEASON: How much transmission does the City of Tallahassee actually own? Is it very significant?

MR. CLARK: In what terms? And I'm not exactly sure I can answer the question.

CHAIRMAN DEASON: Well, I guess the bottom -- well, I guess what I'm getting to is do you consider in your planning not only the addition of generating capacity, but the enhancement of transmission to transmission assets and look at that as to which is the least-cost alternative?

MR. CLARK: Certainly. We do internal studies that feed off of the statewide database for the statewide transmission system. And any enhancements that are made that can benefit us are reflected in that database. Case in point, and referenced in the presentation is the constraint that we see to import that results at the Scholtz/Woodruff line, which is the line that connects Georgia Power to Florida Power Corporation there at the

Apalachicola River. There are some enhancements, to our understanding in talking with Florida Power Corporation, too, that are planned for that line in the 2002 time frame which mitigate that constraint somewhat.

MR. HAFF: Are there any questions for the City of Tallahassee?

Okay. Thank you.

MR. CLARK: Thank you.

MS. STERN: Seminole Electric Cooperative is next.

MR. ZIMMORMAN: Good afternoon, Commissioners and staff. I am Garl Zimmorman, Manager of System Planning at Seminole Electric Cooperative, and what I would like to do is just touch briefly on the last two slides in your packet which show our generation facility additions planned in the future over the ten-year planning horizon.

The first slide, which is out of the -- Schedule 8, out of the 1999 ten-year site plan, actually showed 12 generic combustion turbines required over the planning horizon. Those were just listed as, like I say, generic 150-megawatt combustion turbines, with some of those in service as early as the fall of this year. We have met many of those needs already. The first -- some of the first needs were met by some seasonal purchases, a seasonal purchase with the City of Tallahassee, another one that is imported, an import purchase from Georgia. We have signed contracts with Reliant for the capacity of two combustion turbines from their Hollapar (phonetic) project. We have signed a contract with Constellation for the capacity of two combustion turbines from their Oleander project.

Then turning to the next slide, which is out of our 2000 ten-year site plan, we showed another unknown combustion turbine to be in service by November of 2002. Again, we have satisfied that need with an additional combustion turbine from Constellation's Hollapar project.

We have fine-tuned the requirements that were in last year's program. Now we are showing the actual CTs with their seasonal variation in capacity and, also, fine-tuned our needs between peaking and intermediate capacity and are showing a couple of one-on-one combined cycle units.

We presently have an RFP out with bids due tomorrow for the first of those combined cycle units, which is to be commercial in service the summer of 2004. We anticipate having a short list of those bidders available by the end of this year and make a decision shortly after the first of next year. So we are well on the way to satisfying the needs that we had shown in last year's ten-year site plan. And with that I will be glad to entertain questions.

MR. HAFF: Go ahead.

CHAIRMAN DEASON: You actually have signed contracts with Reliant and Constellation, I believe?

MR. ZIMMORMAN: Yes, sir.

CHAIRMAN DEASON: Okay. I don't want you divulge any confidential information, so if it is, let me know. But my question is, in those contracts is there an escalator for the price of gas or is all of that risk on the providers?

MR. ZIMMORMAN: On both of those -- both of those contracts fuel is a pass-through.

CHAIRMAN DEASON: It is just a pass-through?

MR. ZIMMORMAN: Right.

CHAIRMAN DEASON: Okay. Now, do they purchase their fuel and show you what they pay for their fuel or do you purchase the fuel that they use to generate for you?

MR. ZIMMORMAN: They will purchase the fuel, but our fuels department will be very intimately involved with their people on their fuel contracts.

COMMISSIONER JABER: My question related to those two contracts. And you may have said this, and I just missed it. How many megawatts have you entered into a contract for with Reliant, and how many megawatts for the Oleander plant?

MR. ZIMMORMAN: Reliant is for two CTs, which is approximately 300 megawatts in the summer, about 360 in the winter. Constellation, the initial contract was for the same amount, two CTs and then we added a third CT, which is another 150 in the summer, 182 in the winter.

COMMISSIONER JABER: Thank you.

MR. HAFF: I've got a question on the last page there. You just mentioned that the RFP is due, I guess, tomorrow on the first of those unknown combined cycles. What is the proxy for that? Is that based against the next combined cycle at Hardee?

MR. ZIMMORMAN: It would probably be a one-on-one combined cycle unit at our -- at the Hardee site, which we now call our Paine Creek site. We think that there will be -- we think we will receive bids for capacity. We are not anticipating that we are going to need to self-build. Of course, we will evaluate bids against a self-build option.

MR. HAFF: Okay. And assuming, I guess, for this argument that every one of these units in the ten-year site plan for 2000, these three unknown gas turbines and two unknown combined cycles, assume that they are all built for Seminole. Is the Paine Creek site, you know, formerly Hardee site, is it certified to handle all of that capacity?

MR. ZIMMORMAN: It is not presently certified for that much capacity. We would need additional certification. In addition, there would be additional transmission required. When we go -- there is transmission capacity for about 300 megawatts above the Paine Creek unit. Beyond that, then there is transmission improvements required which enter into the economics of that site versus a new Greenfield site.

MR. HAFF: Does Seminole own or -- I guess at the Palatka location, is there any additional -- is there sited capability to build it there should it be needed there?

MR. ZIMMORMAN: Again, it is not sited. There is physical room for additional capacity there. We would have to, again, evaluate the transmission capability. Being that far north in the state, it can create transmission problems injecting additional capacity into the state grid at that point.

MR. HAFF: Okay. So the likely location, I guess, based on what you know now, is it would be somewhere in Central Florida?

MR. ZIMMORMAN: Probably more in the center part of the state.

MR. HAFF: Okay.

MR. ZIMMORMAN: Not necessarily Hardee. We are looking at some other sites. We don't presently have options, although we are investigating other potential sites.

MR. HAFF: Okay. Are there any other questions for Seminole Electric Cooperative? Okay. Thank you.

Next up there are four merchant plant companies that filed ten-year site plans with the Commission. They were filed prior to the, you know, Supreme Court's order. But in any event, what I wanted to do was give them an opportunity to present anything they have or be here for any questions that we may -- people may have on those plans. So with that I will start with Duke Energy, New Smyrna Beach.

MR. GREEN: Thank you. This is Mike Green with Duke Energy, North America. I've got 53 slides that I won't show you.

MR. HAFF: Thank you.

MR. GREEN: We'll answer any questions, however. We would like to say Duke Energy, North America stands by the filing we made in April of this year to bring 514 megawatts of merchant capacity into the state, with one exception to that filing. That exception would be the commercial operation date that is stated in there of June of 2002. I do not know what date to put in there now, given the current status of the Supreme Court rulings and the lack of clarifications on the motions for rehearing.

So the June 2002 date, unless I can start construction in three months, is not a reasonable commercial operation date for that facility, but does not lessen the intent of Duke Energy to provide low cost reliable merchant wholesale power to the State of Florida.

And I would answer any questions you have.

CHAIRMAN DEASON: I have a question. Do you still have the ability to obtain the natural gas commitments to fuel this plant if it were to be built?

MR. GREEN: Yes. We have a long-term contract with Citrus, Florida Gas Transmission, to provide the gas. And we had several years that we could re-up that contract, if you will. We have still got a couple of more opportunities to extend it.

MR. HAFF: My questions -- I have got a couple of questions, really more procedurally about what to do with the ten-year site plan that you filed. We are required to classify it as suitable or unsuitable as a plan. And if -- I guess I'm asking you to fortune-tell for a minute. What do I do with your plan if the Supreme

Court upholds its decision and your plan is based on a unit that they say can't be built? What do I do with your ten-year site plan? Do you withdraw it, or do I recommend it is unsuitable, or what do I do?

MR. GREEN: I really don't have an answer for you. I think you have got to wait and see if there are any clarifications from the Supreme Court's deliberations on motions for rehearing, see if there is anything that will clarify the issue there.

MR. HAFF: Okay.

MR. GREEN: But bottom line, I think the state law of Florida requires a power plant with a steam cycle greater than 75 megawatts to obtain a certificate of need, but there doesn't appear to be a -- who has the authority to grant that certificate is unclear. Clearly, I think what needs to happen is see what the clarifications are from the Supreme Court, number one; see what views the Energy Study Commission that the governor has appointed might have and see if the Legislature does anything to clarify it next session.

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

MR. GREEN: Thank you.

MR. HAFF: Is there someone from Okeechobee Generating Company here? Okay.

COMMISSIONER JACOBS: I have a question for Duke, actually. It could be for either one of them, but since you filed one, I am interested in how you determined what your demand was in the plan that you filed.

MR. GREEN: The demand we utilized in our determination of need was the overall Peninsular Florida need for electricity, combined with where a 6800 BTU combined cycle plant will fit in the supply stack. The fact that Florida is growing by approximately 11,000 megawatts as all the ten-year site plans identify, part of that 11,000 megawatts is met by what many utilities specify as unspecified or undetermined sites, unnamed, not sure where they are at yet, but they are undetermined sites as yet. Also there is a tremendous amount of wholesale purchases in each of the utilities' plans to meet their retail need. So the need that Duke Energy utilizes in our need determination was the tremendous amount of growth of Peninsular Florida in the overall need, and the fact that the individual retail utilities are providing that need by sometimes unspecified plants and wholesale purchases from someone. Those wholesale purchases have to come from somebody, and me being a wholesale provider, I would suggest I am one.

COMMISSIONER JACOBS: When you say your need determination, you use that same analysis in your -- in the site plan that you filed, as well?

MR. GREEN: Yes.

COMMISSIONER JACOBS: Okay.

MR. HAFF: Commissioner, are you asking whether the table in the plan laid out what their projected demand was? There is a table in the ten-year site plan that lists demand that utilities fill out by residential, commercial and industrial.

COMMISSIONER JACOBS: Right.

MR. HAFF: Is that what you're asking?

COMMISSIONER JACOBS: That was, but his answer was probably more in line with what --

MR. HAFF: Those forms are blank in their ten-year site plan.

MR. GREEN: We have no retail customers, so there are many forms in the required forms that we can't really fill in. However, we have done the assessment of what our -- based on what our heat rate is and what we could offer energy as and how much energy then could be sold that would be, basically, displacing the 23,000 megawatts of capacity in the state today that has a higher heat rate. And assuming the fuels are going to cost the same amount, it's when can we sell energy cheaper than what exists at a higher heat rate plant. That's the capacity factors that we utilize in our plans.

MR. HAFF: Okay.

COMMISSIONER JACOBS: Very well. Thank you.

MR. HAFF: Thank you.

Mr. Moyle.

MR. MOYLE: John Moyle, Jr. of the firm of Moyle, Flannigan. We're counsel of record for Okeechobee Generating Company. And we would stand by the written submission that we previously made.

I would like to just make a quick comment with respect to a question that staff asked about what happens with respect to a finding of suitability or unsuitability on these plans. And I believe there is precedent. I think Florida Power and Light last year or the year before, withdrew a plan. So if the Supreme Court does not reverse its decision, that is surely an option, I think, that would be available. And if that law is not settled at that time, then I would suggest a finding of suitability would be appropriate.

MR. HAFF: Okay. Any questions? Okay, thank you.

Is there someone here for Oleander Power Project?

MR. LOYLESS: Commissioners, I'm Elliott Loyless, a consultant to the Oleander Power Project. We had not planned on a presentation today, and I would have given you the respect of a tie had I known. But we stand by the ten-year site plan that we filed.

The only possible change that we know of is the in-service date, currently June 2002. Our new target is May of 2002. And, obviously, it could be two or three months one way or the other. That is still well ahead of Seminole Electric Co-op's needs.

MR. HAFF: I will ask you the same question I asked Mr. Green. What should we do with your ten-year site plan, assuming -- I guess, fortune-telling, if the Supreme Court upholds its order, what do I do with your ten-year site plan?

MR. LOYLESS: Our legal advice has been that we are not effected by the Supreme Court decision.

MR. HAFF: Okay.

CHAIRMAN DEASON: And that is because of the configuration of your plant and the technology?

MR. LOYLESS: That's correct. And there was some question that we might be involved anyway. But, again, we have been advised that we are not.

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

Okay. Is there someone from Calpine Construction Finance Company here?

MR. EVES: I'm Tim Eves from Calpine. And thank you for the opportunity to come and talk today.

We stand behind our ten-year site plan, but it is somewhat of a fluid process, so I thought I would tell you where we stand in the status of our projects.

Just briefly, for those of you that don't know Calpine, we are operational in 27 states. We have over 5,000 megawatts of wholesale generation. We have 10,000-megawatts currently in construction and development. We own significant gas reserves and have an acquisition program in place for buying additional gas reserves.

Here in Florida we own the 150-megawatt cogeneration plant in Auburndale called the Auburndale Power Partners. We sell the power from that facility under contract with Florida Power Corp and Tampa Electric. We sell our cogeneration steam to Catrelli Citrus Processors and Florida Distillers. We are in the process of adding another 100-megawatt peaker at that facility and our permit applications are in place. We expect to have that operational by next summer.

We have our Osprey need petition pending before the Public Service Commission. We filed our site certification application for our Osprey plant in March of this year. That is a 540-megawatt combined cycle plant.

There was a question earlier regarding air permits. We have our draft air permit issued for that plant.

We have interconnection studies and our transmission access studies underway with Tampa Electric. We expect the commercial operation of that plant in early 2003.

We have also announced our Blue Heron facility, which is a 1,080-megawatt facility over in Indian River County. Our site certification application and need petition are in process, and we will be filing those late September, early October.

We have our interconnect and transmission access agreements in place with Florida Power and Light, and we were one of the entities with Florida Power and Light who waived the confidentiality requirements. We expect commercial operation of that plant in late 2003.

Now, as seen by the ten-year site plans, a lot of the discussion here, there is a significant need here in the state. And as Mike Green said, there is unidentified plants that have been specified to meet those needs. We are in the process of contracting with a number of utilities in the state for capacity so that the capacity from our plants will help meet some of these unspecified needs. We would like to think of our plants as contract plants instead of merchant plants.

Our ten-year site plan also identified two additional sites that we have under contract. We have options on a number of other sites. We also acquired Sky-Gen (phonetic) since the filing of our ten-year site plan. Sky-Gen has a subpower plant siting act Santa Rosa project in development up in Pensacola that now will now become one of our projects. And we are working on a number of other acquisitions and strategic alliances here in the state.

And I would just like to say we have noted your decision, the Commission's decision on the wholesale incentives for the IOUs, and we are encouraged by that decision, thinking that you are speaking in support of developing a more robust competitive wholesale power market here. We are here. We are going to build power plants, and we are excited to be a part of this emerging market.

And that is my presentation.

COMMISSIONER JABER: And you're sticking to it.

MR. EVES: That's right.

COMMISSIONER JABER: Do contract plants provide wholesale or retail?

MR. EVES: They will provide wholesale power, and we are working on contracts with entities in the state that have retail load.

COMMISSIONER JABER: You provide wholesale services to plants that provide service to retail, to the ratepayer, basically?

MR. EVES: That's correct. Actually, you know, a few have submitted some letters on our behalf to the Commission, like FMPA, OUC and Reedy Creek. Those are good examples of the folks that we are talking with about contracting some of our wholesale capacity that they will buy to meet their retail loads. As Mike said, there is a wholesale market. A lot of these guys are buying their wholesale power from somebody. And that is just an example of the few that we are talking to about buying some of our wholesale power.

MR. HAFF: I'm going to ask you the same question regarding the -- I guess, procedurally how to treat your ten-year site plan if the Supreme Court upholds its decision sometime soon before this report comes out in November. Do you have an opinion as to what you should do with your plan if the units that comprise that plan are decided that they can't be built?

MR. EVES: I think what the Supreme Court said is if your plant is not committed to meeting the needs here in the state, you can't build it. Our plant will be built based on contracts to meet the capacity needs here in the state. So I don't think the Supreme Court decision, if it stands, will apply to our plants.

MR. HAFF: Do you have -- I mean, you're kind of reading the future here, I guess. Do you know if that will be done by November when this report goes to them for their consideration?

MR. EVES: Mike, I would submit it doesn't matter how the Supreme Court comes down. If they come down and affirm their decision, I think because our -- because we are going to build our plants based on contracts, we can go forward. I think if the Supreme Court comes down and reverses themselves, it will just make it that much easier for us to go forward as well as some of my colleagues here.

MR. HAFF: Okay.

MR. EVES: So I would say our site plan ought to be held as active or good or whatever your -- you know, whatever you classify it as.

MR. HAFF: Okay. Are there any other questions for Calpine? Okay. Thank you.

MR. EVES: Thank you.

MR. HAFF: Next on our agenda is we typically hold time for the public or other interested parties to give their presentations or comments on the specific plans or the plans in general. And, I guess, right now we'll have those public comments, if there is anyone that wishes to speak to the Commission.

Okay. I guess that is -- I will turn it over to you now.

CHAIRMAN DEASON: Okay. Thank you.

I just want to take an opportunity to thank everyone for coming, preparing your plans, participating in this workshop. I don't want to give the false impression because we worked through lunch and tried to do this quickly that we weren't interested in your plans. That is certainly not the case at all. Your participation is greatly appreciated. And if there is nothing else to come before the Commission at this time this workshop is concluded.

Thank you all.

(The Workshop concluded at 1:12 p.m.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, FPSC Bureau of Reporting, Official Commission Reporter, do hereby certify that the Workshop (undocketed) was heard by the Florida Public Service Commission at the time and place herein stated.

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, consisting of 131 pages, 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 25th day of September, 2000.

Jane Faurot

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