BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

COMMISSION WORKSHOP

UNDOCKETED

ORIGINAL

In re: Commission Review of Electric Utility Ten-year Site Plans.

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COMMISSION WORKSHOP

The above-entitled matter came on to be heard before the Florida Public Service Commission, Honorable JULIA JOHNSON presiding as Chairman, at Room 148, the Betty Easley Conference Center, 4075 Esplanade Way, Tallahassee, Florida, on the 8th day of August, 1997, commencing at approximately 9:30 a.m.

Reported by:

RAY D. CONVERY

Court Reporter

PRESENT

JULIA JOHNSON, Chairman

SUSAN CLARK, Commissioner

JOE GARCIA, Commissioner

TERRY DEASON, Commissioner

DIANE KIESLING, Commissioner

P R O C E E D I N G S

CHAIRMAN JOHNSON: Good morning. I'm going to go ahead and call the Ten-year Site Plan Workshop to order this morning.

Are there any members of the public who would like to testify or present any comments to us today? And if so, we're going to have staff walk us through the process, but I did want the members of the public to come forward and make yourselves comfortable.

Terry Reid is here to our left here to assist anyone that's not familiar with the process that would like to participate. Please feel free to talk with him if necessary or, if not necessary, you can just come forward.

Staff, let me turn it over to you to make introductions and to let our audience know what the process will be today.

MS. PAUGH: Thank you, Chairman Johnson.

This time and place have been set for this workshop of commission review of electric utility ten-year site plans, pursuant to notice issued on July 8th, 1997. Because this is a workshop, it is not necessary to swear the witnesses. There is an agenda for this workshop which will include opening remarks by the Chairman, introductory remarks by staff, public and interested persons' comments, statewide assessment by the Florida Reliability

Coordinating Council, and then individual utility assessments. 15 minutes per presentation have been set aside for this. Thereafter, we will have closing remarks by staff.

CHAIRMAN JOHNSON: Okay. Staff?

MR. HAFF: I guess with that, we can -- oh, I'm Michael Haff. I'm with the commission staff, and I just wanted to add that, when people make their comments or the utilities make their presentations, to please give their names so that the court reporter will have a record of it, and any presentations or handouts that you have, make sure that the court reporter also gets a copy of that, as well as Commissioners and staff.

And I guess with that, we can take the public comments or interested persons who have comments on the plans and start with them.

CHAIRMAN JOHNSON: Lee, would you like to --

MS. KAMARAS: Good morning, Commissioners. I'm Gail Kamaras with the Legal Environmental Assistance Foundation. The report you've just been handed is LEAF's report card on nine of Florida's electric utilities, and we do have a copies of the full report for those utility representatives. We also have a summary report that others may pick up.

This report's on the electric utilities, their energy choices now and for the future as projected in their ten-year site plans, the pollution those choices cause, and the lack of progress on either energy savings or use of renewable resources.

We find in the report card that the utilities' performance is unsatisfactory as we hope the Commission will find their ten-year site plans unsuitable, and we urge them to improve their performance.

Florida's considerable array of legislative and other public policies favoring the wise use of energy resources must be implemented vigorously to set the direction toward a sustainable energy future for the state. Electric generation is the most polluting human activity. Our report shows hundreds of thousands of tons of pollutants, and it's in the millions of tons for carbon dioxide, from nine plants alone, nine utilities, alone -- excuse me -- being put into the atmosphere, some of which also reaches our water resources.

Those pollutants cause acid rain, smog, soot and global climate change. This pollution also has widespread and serious health and environmental effects in Florida. The cost of this pollution is not zero and we urge the Commission to exercise its authority to consider those costs in its decision-making.

Also, as the Commission is well aware, the electric industry is beginning to undergo a major structural change towards competitive generation. At some point in the next several years individuals will choose their electric supplier. We need to begin the consumer education effort now by disclosing to consumers the content of their energy supply. Consumers have a right to know where their electricity comes from and what pollution it causes.

I brought with me a consumer product. We know more about the content of a bag of Cheetos than we do about our electric supply, and that's because we have food labeling. We need something similar for electricity.

We urge the Commission to begin the process of disclosure by requiring utilities to disclose the pollution and fuel information to their customers on a regular basis and in a manner that is easy to understand.

I'll just close by saying we can't keep doing the same thing over and over again and expecting a different result. If we continue business as usual, making the same electric power choices in the same manner, we'll keep choosing the same dirty and dangerous power sources and we will never get to real energy savings, a healthful environment or a sustainable energy future for our state.

Thank you.

CHAIRMAN JOHNSON: Thank you.

MS. SWIM: Commissioners, I'm Deb Swim, also with LEAF. My comments today focus on energy efficiency and the Commission's responsibility under FECA, the Florida Energy Efficiency and Conservation Act, responsibilities which warrant a finding that the utility plans before you are unsuitable.

FECA directs the Commission to require the utilities to implement energy efficiency programs. It states the Legislature's belief that utility energy efficiency programs are, quote, "critical to the," quote, "health, prosperity and general welfare of the state and its citizens," end quote.

Unfortunately, as the utilities' own conservation program performance reports and ten-year plans show, utility energy efficiency programs supply only a tiny fraction of Florida's electric service needs. In fact, as you'll see in LEAF's report card, last year less than one half of one percent of all utility energy services were provided to customers by utility energy efficiency programs. This is much less than could be provided at a cost less than power plants, even without factoring in environmental costs. We can do better and we should.

Florida's utilities have done better at another FECA directive, and that is reducing peak demand. One utility, Gulf Power, implemented a peak reduction program that caused energy use off-peak to increase, sacrificing, if you will, energy efficiency on the altar of load management. Load management is well and good, but it is not nearly enough.

It's time utility conservation programs achieved more through energy efficiency, especially when energy efficiency measures cost less than generating power, otherwise utility ten-year plans will continue as do the ones before you to project a larger demand for energy than need be and more power plants will be built than make economic and environmental sense.

Thank you for the opportunity to comment.

CHAIRMAN JOHNSON: Thank you. Ms. Elder.

MS. ELDER: Thank you, Madam Chairman, Members of the Commission. My name is Marcia Elder and I'm speaking on behalf of the Project for an Energy Efficient Florida, and we appreciate the opportunity to offer brief comments today on the issue of utility plans for future generating capacity.

We are not surprised by what we have read for a variety of reasons, but we are indeed disappointed because fundamental needs of the public are not being addressed. We live in a state whose leaders are saying that we want and we intend to be sustainable, yet renewable energy and energy efficiency are not just desirable, they are essential to sustainability.

I've had the pleasure over the past year of serving on a policy committee that has been comprised of a very diverse range of interest groups on a statewide basis, talking about sustainability issues, and in our final report we concluded that renewable energy is a pivotal ingredient or is the pivotal ingredient to Florida becoming sustainable. Yet, when you look at the role of renewables in the utilities' fuel mix both now and in the future, it turns out to be virtually zero.

As pointed out in the report card by LEAF, the role of energy efficiency is likewise slim by comparison with the potential, despite its many benefits. The benefits of sustainable energy, meaning renewables and energy efficiency, are wide ranging: Energy savings, pollution reduction, lower utility bills, reduced reliance on imported fuels which are very significant to our state, truly diversifying our fuel mix, reduced destruction of the environment through extraction of fuel resources, creating significant opportunities for economic development and job creation and international trade and improved business competitiveness, protecting Florida's natural systems which in themselves have an important economic value, improving our global competitiveness necessary as a state, buffering the state's economic mainstays which are energy intensive, avoiding property damage from pollution which is truly a property rights issue, protecting against adverse health impacts, increasing consumer self-reliance, and freeing up capital for more productive expenditures elsewhere in the economy. And when you consider right now that Floridians spend over $21 billion a year on energy and the fact that most of those dollars leave our state and go to other states, they benefit other states' economies and other nations' economies rather than our own by being put to use here through indigenous energy resource and energy efficiency, all of which goes to the heart of the question before: Do we need to bring an additional 7,000 megawatts worth of fossil fuel generating capacity on line as called for in the utility plans?

The answer lies in the assumptions upon which the numbers are founded. If you make a status quo assumption, for example, you tend to get similar results to the way it's always been, but I believe that it was Albert Einstein who said that "The solutions of the past will be inadequate to address the challenges of the future," where we would submit that it's time to step beyond many of the assumptions of the past that are simply outdated.

We can't get to where we need to go as a state and as a nation if we make or if we accept such claims as renewables are not cost effective while we continue the pattern of decades of heavy federal subsidies for fossil and nuclear fuels, the absence of incentives for renewables, policies that encourage the sale of more energy, not it's efficient use, and cost-effectiveness tests that expressly exclude considerations to which we should be ascribing great value, such as the worth of our environment and public health.

We do understand that this is a challenging time in the utility regulatory arena, particularly given the uncertainties of restructuring, but as Michael Douglas said in his role as the "American President," a movie which I commend to everyone in this room as a model of courage and on energy policy issues in particular, "This is a serious time, and it takes serious people to address the challenges that we face." And it is in that spirit that we urge you to scrutinize the plans before you, and in your decisions on this and on other matters, that you lead Florida in a new direction based upon a vision of true sustainability and founded on the public's best interests for now and for the longer term.

Thank you for the opportunity to offer comments today.

CHAIRMAN JOHNSON: Thank you, Ms. Elder.

Commissioners, any questions?

COMMISSIONER DEASON: Yeah, I have a question concerning the report card report. I'm looking at page 13. Who should I ask that question to?

MS. SWIM: Go ahead.

COMMISSIONER DEASON: I'm looking at Graph 7, and the -- I guess the description of that is -- starts on page 12, but anyway it -- at the top of it it says that less than one percent of all utility energy services were provided to customers by utility energy efficiency programs in 1996. It says that's depicted on Graph 8, but I think that really is Graph 7, is that correct.

MS. SWIM: Yeah, I think you're right.

COMMISSIONER DEASON: Could you explain to me what that is intended to represent? That's one year, 1996, is that correct?

MS. SWIM: This is 1996, and what it represents is the total megawatt hours generated and what -- generate -- the total megawatt hours in terms of energy services that all of the investor-owned utilities provide, and --

COMMISSIONER DEASON: So the 99.6 percent, that's the total megawatt hours generated by all electric utilities?

MS. SWIM: It's the investor-owned --

COMMISSIONER DEASON: Investor-owned.

MS. SWIM: -- utilities, and it takes the megawatt hours that are generated, adds it to the megawatt hours saved, and that gives you the total.

COMMISSIONER DEASON: Okay. Now where you get the number for the megawatt hours saved?

MS. SWIM: The sources of that the data at -- of that particular data are the utilities' conservation performance reports that were filed this year.

COMMISSIONER DEASON: So that's on file with the Commission?

MS. SWIM: Yes.

COMMISSIONER DEASON: Now -- so the 99.6 percent, that's total megawatt hours generated in 1996.

Now, I'm just asking --

MS. SWIM: Well, it's more than just --

COMMISSIONER DEASON: Okay. Go ahead, that's fine.

MS. SWIM: The circle there, the whole of the circle is the sum of the kilowatt hours generated plus the kilowatt hours saved, and the slice is the portion that is kilowatt hours saved.

COMMISSIONER DEASON: The total kilowatt hours that are generated in 1996, that's your base; is that correct?

MS. SWIM: No. The base is kilowatt hours generated plus kilowatt hours saved. We see that as the energy services required.

COMMISSIONER DEASON: Well, I guess the question I have is that there have been conservation programs implemented in prior years which have resulted in savings in prior years and, obviously, there's not going to be generation to meet a demand that's not there. So you're discounting or ignoring the conservation that has taken place in previous years in this calculation, is that correct?

MS. KAMARAS: This is a report card for one year of utility performance. We intend to do this again next year.

To the extent that it ignores previous energy savings, it also ignores previous generation. So it compares apples to apples in one given year.

COMMISSIONER DEASON: So have you done a study, a baseline study from the beginning of FECA to determine what the generation was then and what it would have been with no conservation programs at all and compared that to the conservation that took place to see what the trend's been over time and what the cumulative effect of all the conservation programs have been over that entire period of time?

MS. KAMARAS: We haven't done it since the beginning of FECA, but we did an informal look-back over the last several years that the utilities have been performing under the new conservation goals rule, and the results were not much better.

CHAIRMAN JOHNSON: Any other questions?

Ms. Kamaras, you had mentioned in your presentation about -- when you used the example with the Cheetos, about what information you thought should be provided to customers, and I think it was -- you -- I'm trying to better understand what you had in mind. On page 8 you have a chart that -- of your report card, "What does your utility use to make electricity?" Is that the kind of information that you believe that we should be providing to our customers and, if so, in what fashion? How should we go about better educating them on these issues?

MS. KAMARAS: These charts are a little bit complex. Actually there's a lot of work being done right now on the issue of consumer disclosure. The Regulatory Assistance Project in Maine, which provides information to NARUK and to state commissions, has some detailed information about this issue. What they've suggested basically is a nutrition type labeling with perhaps a pie chart showing this much of your energy comes from coal, oil, hydro, solar, and break it out that way, and then to have sort of a graph for the pollution effects with a line against some performance standard that would be designated or against a line showing average regional emissions so that it's very simple. It's a two-part label.

CHAIRMAN JOHNSON: Okay. And that would be in their -- something in their bills or --

MS. KAMARAS: It would be something in the bill, if not on a monthly basis, then perhaps on a quarterly basis or a semiannual basis.

CHAIRMAN JOHNSON: And you said that other states are doing this now?

MS. KAMARAS: Other states are looking at this, and I think we need to start looking at it, too.

COMMISSIONER CLARK: They're looking at it. They're not doing it, are they?

MS. KAMARAS: I don't think anyone has adopted it yet because they're just not there, but it's something to start looking at, and I think, you know, this commission has some experience with the amount of confusion that consumers have experienced in telephone deregulation and the need for a massive and long-term consumer education effort. We can't educate them enough and we can't educate them too soon, and our belief is that we need to start getting them used to this idea now.

CHAIRMAN JOHNSON: Okay. And with respect to the green pricing, I don't know if you mentioned it, but it's in here. What are your suggestions there as it relates to the Commission or as it relates to educating the customers, again?

MS. KAMARAS: Well, green pricing programs are a start. They're sort of a showcase effort, but again they get the utility and the customer used to the idea of dealing with renewable resources, and in this case, you know, particularly solar power, we commend the utilities that have started green pricing programs. We think that perhaps in the future they may move to green marketing programs where they're doing this as a business venture. I know that Lakeland is looking into something like that and it's very innovative and creative.

CHAIRMAN JOHNSON: Could you say that again? I'm sorry to cut you off, but you said Lakeland is looking into doing what?

MS. KAMARAS: Lakeland is looking into a green marketing program and, you know, we would be interested in seeing where that goes. Gainesville and Tallahassee are looking into green pricing programs that -- or Gainesville has one. Tallahassee is now starting one. Florida Power & Light is going to begin one, but these are baby steps and we need to go beyond those baby steps if we're really going to have an energy future in this state.

COMMISSIONER CLARK: Explain to me the difference between green pricing and green marketing?

MS. KAMARAS: Green pricing is basically consumers giving voluntary contributions to a program which the utility may or may not match with its own funds. In the case of the City of Tallahassee, for example, they are going to match any customer contributions 50 percent.

In green marketing you're selling a product and the customer's paying for that product. It's not -- you know, it's not something that's a --

COMMISSIONER CLARK: They -- in effect, they say, "I want to pay to get my electricity from a renewable resource"?

MS. KAMARAS: That's correct. It's not just going out to the world at large.

COMMISSIONER CLARK: I would appreciate it if you would keep us informed of the details of what you know in other states and what they're doing. I would assume it's part of just informing the public on their choices, and this is one of their choices. For instance, it may be California that's doing it on the green marketing.

MS. KAMARAS: Green marketing is starting to occur in a variety of states, but in the states where we still have a full monopoly system, customers really don't have a choice.

Part of what we're hoping from the public distribution of the report card is that customers will start telling their utilities, "Hey, we want more." It's very clear from polls that have been done, surveys done over the last ten years or more -- actually since the mid-'70s -- that there is a huge population out there, a tremendous population -- consistently the polls show in excess of 70, 75 percent of the public wants greener resources and that they're willing to pay more for it if necessary, and the utilities really need to start listening to that.

COMMISSIONER GARCIA: Where this pricing is occurring, what kind of price differential is occurring between the green prices and the prices of regular provision of service?

MS. KAMARAS: Well, in the green pricing it's really hard to say what the price difference is because the customers are basically buying the equipment for the utility and they're paying, you know, in some cases utility's administrative costs for the program, and there's a range of stuff. There's a wind system in Traverse City, Michigan, and the Sacramento Municipal Utility District has been putting solar panels on people's roofs, and that solar power does not go to that individual. It goes into the grid and it benefits all the Sacramento customers, and the range is, you know, in the contribution programs, anywhere from, you know, a dollar, two dollars a month to the Sacramento program, which is probably about six dollars a month, and I'll mention that the Sacramento program has been so successful that they have driven the price of solar electricity down to where their contracts that they have signed for I believe it's the year 1999, they are purchasing solar electricity power at three dollars a watt, which is the number that has been tossed around as the magic number to make it cost-effective across the board; and if we could do that here in Florida, we would have a golden opportunity to create jobs, you know, keep money in the state, as Marcia pointed out, develop international trade.

COMMISSIONER GARCIA: It's certainly something that we might want to consider as experimental to see if there's any demand out there and see if customers are willing to invest in that type of system.

MS. KAMARAS: They are, if it's sold right.

You know, a lot of it depends -- the survey results you get back depend on the survey questions you ask. We've seen a couple of surveys or questionnaires that have been done by the utilities in the state. They got a poor result. That poor result was built into the kind of questions that were asked.

The City of Tallahassee, on the other hand, participated in a nationwide survey that was done by several municipal utilities, and they got back terrific results, and I can't believe that the people in Tallahassee are that much cleverer than the people in the rest of the state of Florida. We'll give them a small increment of cleverness, but not that much more.

CHAIRMAN JOHNSON: Any other questions?

MS. ELDER: Madam Chair, if I might add to that, with the California program for PV, for at least the last several years, customers have been standing in line to be able to have those systems on their roof. Again, they don't own the system, but it is there as part of the utility's overall system, and they have a long waiting list of customers who, because the program -- they can only put out so many systems, of customers who want to participate in that; and for Florida, it's clear the surveys, as far as the environmental support in our state, as well as the support for these kinds of initiatives, is so very high, but the customer has to have the opportunity before they can take advantage of it, and right now they simply don't have it.

The green pricing program, as a voluntary program, it is a good step forward, and at the same time it's a very limited step forward, and it only works, as Gail has pointed out, if the program is designed for success and if it is implemented, and they're being partially implemented at this time. So we'd like to see a much larger step forward towards sustainability.

COMMISSIONER GARCIA: I might be curious just to have it costed out based on what's already being done and seeing if you can cover at least those costs, and that gives you a window to begin a marketing perspective from there, but it certainly does present some interesting possibilities, and like Commissioner Clark, I'd love for for you guys to keep us informed.

CHAIRMAN JOHNSON: Any other questions?

Thank you very much for your comments.

MS. KAMARAS: Thank you.

MR. HAFF: Following the agenda that we mentioned earlier, we're going to hear from the Florida Reliability Coordinating Council for a statewide assessment and we'll start from there.

MR. HERNANDEZ: Do you want me to try to use the mike?

CHAIRMAN JOHNSON: Yeah, we'll need you to use the microphone.

MR. HERNANDEZ: Good morning, Commissioners, Commissioner Johnson. My name is Tom Hernandez. I'm the Director of --

CHAIRMAN JOHNSON: You might have to hold it up a bit more.

COMMISSIONER CLARK: Don't we have a lavaliere we can give him?

MR. HERNANDEZ: I could try sitting.

COMMISSIONER KIESLING: I think you need to.

MR. HAFF: Commissioners, we -- would you prefer to sit here and look at the screen or can you see the TV okay?

CHAIRMAN JOHNSON: Will it show up in our monitors?

COMMISSIONER KIESLING: Yeah, it's on our monitors.

CHAIRMAN JOHNSON: Yeah, we're fine.

MR. HERNANDEZ: Is it legible on your monitors?

COMMISSIONER KIESLING: Yes.

MR. HERNANDEZ: Let me re-start. My name is Tom Hernandez. I'm the Director of Energy and Market Planning for Tampa Electric Company. This morning I'm representing the FRCC, the Florida Reliability Coordinating Council, and before I start my presentation, would it be appropriate or is it appropriate that I have a follow-up to Commissioner Deason's comments on the report card, 30 seconds?

CHAIRMAN JOHNSON: That's fine.

MR. HERNANDEZ: Okay. An alternative -- and I agree with your comments regarding the report card, and again I haven't seen the report card. It's probably in the mail or I just haven't seen it yet, but along the lines of what you were suggesting about looking at cumulative benefits I think is on track. The alternative would be to look at the incremental generation from year one to year two and then to use the incremental conservation of energy that was reported in the information that was referred to. So that's a quicker way to look at an incremental benefit and would show a different picture, I believe.

COMMISSIONER DEASON: So you're saying that, to get a -- over a long-term period, you need to do it on a cumulative basis to see what the effect of conservation programs have been over the entire period of time, the cumulative effect of that, and if you're going to do it on an incremental basis, you shouldn't be the using total generation, you should be using incremental generation versus incremental savings to get it on an apples-to-apples basis?

MR. HERNANDEZ: That's correct.

COMMISSIONER DEASON: Thank you.

MR. HERNANDEZ: To begin my presentation, what we're -- what my presentation is going to cover is based on the 1997 ten-year plan that was filed with the Commission I believe in July of this year, and also I'm going to refer to last year's plan that was filed with I think the Department of Community Affairs at that time. They may be difficult to see. Is that legible on your screen? Okay.

There are black and white copies for the audience.

I've got some up at the front and I believe each of you have a copy.

This first graph is a comparison of historical firm peak demand for the past ten years on the projection, again stating or showing that, as a peninsula, that we still have continued load growth in the state, fully expect that, with the winter peaks growing at approximately a 2.1 percent average annual growth rate over the next ten years, and then for the summer peak, slightly below the two percent, but continued sustained growth for peninsular Florida.

Can we take one second? This was showing up better. Something's not quite right with the video here. I think the lamps are off. Could we just take ten seconds and see if we can correct this?

All right. This next chart is a comparison of the two ten-year plans, the aggregates that I referred to a few moments ago, for a similar year. So in the first upper left-hand chart, we're looking at the winter firm peak and comparing it for the same year, the winter '97-'98, for both last year's ten-year plan aggregate versus this year's ten-year plan, and effectively what we're showing are higher peaks both in the initial year as well as the last year of the ten-year plan. So we're showing the eight years that are common between the two plans, and that effectively rolls true for the total peak as well as for the summer firm peak and the summer total peak.

On an energy basis we're showing a slightly lower average annual growth rate relative to energy, but with the sustained peaks that correlates to a somewhat lower load factor for peninsular Florida.

COMMISSIONER DEASON: Could you go back to that previous slide?

MR. HERNANDEZ: Sure.

COMMISSIONER DEASON: If I'm reading this correctly, as far as winter firm demand -- that's the peak for the winter -- there's been an increase from the '96 ten-year site plan to the '97 ten-year site plan both in the near term and the long term, is that correct?

MR. HERNANDEZ: That's correct.

COMMISSIONER DEASON: And what has caused that?

MR. HERNANDEZ: Well, again, this is a compilation of aggregate forecasts. This is not and has not in the past accounted for coincident load or load diversity within the state. So this is simply taking the individual ten-year plans and adding up their respective system peaks.

COMMISSIONER DEASON: Well, let me interrupt for just a second. The average annual growth rate in '96 -- in the '96 ten-year site plan was projected to be 1.94 percent, and now it's projected to be 2.14 percent, an increase, I can see that.

That small of an increase in the percentage increase results in that differential of 38,000 megawatt hours to over 41,000 megawatt hours? I'm talking -- not megawatt hours, but megawatts?

MR. HERNANDEZ: No, sir. The average annual growth rate applies to the initial year and the final year. It doesn't account for the increase going from last year's forecast to this year's forecast.

COMMISSIONER DEASON: Okay.

MR. HERNANDEZ: But it is higher.

COMMISSIONER DEASON: All right. Thank you.

MR. HERNANDEZ: This next chart is simply --

COMMISSIONER DEASON: Let me interrupt you one more time. You also indicated that the load factor is less because of the -- the peak is going up and the energy usage is not going up as much, but the net effect of those two is that still there is a net reduction in load factor. Do you have --

MR. HERNANDEZ: Yes, sir, comparing the two different aggregate plans, that's correct.

COMMISSIONER DEASON: From '96 to '97?

MR. HERNANDEZ: That's correct.

COMMISSIONER DEASON: Do you have any other information other than that's just the information that was compiled? Do you know of any trends or anything that would account for that?

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

I do understand that the incremental effects as well as the cumulative effects of conservation programs and the impact on reducing energy are included in that calculation or that assessment.

This next chart is a quick summary of what I will call dispatchable DSM. It's the load management and interruptible load that we use in calculating the firm peak as well as calculating the reserve margin, and you'll see the contribution to reserve margin at the end of my presentation.

This next chart indicates not only the load management and the interruptible load but the effective impacts of self-service cogeneration or energy producer capacity generated by qualifying facilities, as well as the effects of conservation associated with peak reduction, and this is for the summer. So in the year 1997, we're showing approximately 35 -- 3,350 megawatts of capacity or energy resource that effectively reduces the firm peak of peninsular Florida, and then, looking out in the ten-year horizon, that increases to a little over 5,000 megawatts.

COMMISSIONER CLARK: I'm sorry, could I go back to the peninsular Florida summary of dispatchable DSM? Did you say those percentages were percentages of the margin of reserve or of total load?

MR. HERNANDEZ: That is a percentage -- it's a relative percentage using the winter numbers of the total amount of dispatchable DSM in the state. This doesn't correlate to reserve margin calculation. What I was suggesting is that, when we calculate the firm peak and the firm reserve margin calculation, these are the numbers that we're subtracting from total peak in order to contribute to reserves. So those percentages are just relative to the total of 3,440 megawatts. So, for example, Florida Power & Light has 1,056 megawatts that represents 30.7 percent of the 3,440. It's just showing relative contribution to dispatchable DSM in peninsular Florida. That's what those numbers are --

COMMISSIONER CLARK: Okay.

MR. HERNANDEZ: -- this chart we already talked about.

COMMISSIONER DEASON: But before you leave that chart, I get from that chart that conservation -- the conservation area there is doubling from 1997 to 2000 -- perhaps more than doubling, and that accounts for a large amount of the increase from '97 to 2006. Am I reading that correctly?

MR. HERNANDEZ: That's correct, both -- you don't see a big change in interruptible load, but the conservation as well as the load management are accounting for the biggest part of that increase.

COMMISSIONER DEASON: Now, this is part of the Commission-approved goals and the conservation programs that are being implemented to achieve those goals?

MR. HERNANDEZ: I'll say yes, but I'm not sure to what extent everyone included the exact numbers that were represented as a result of the goals proceeding, but I believe that is what is shown here.

A similar chart for the winter. The main point here again is to show higher potential of load reduction over the winter months and at the time of our peninsular Florida peak. So the 5,000 -- roughly 5,000 megawatts by the end of year 2006 is closer to 6200 megawatts for -- using the same resources but over the winter months, we have a higher potential for load reduction.

The next chart again reflects the incremental contributions versus the cumulative to address that point again, but what you see in here is the energy reduction and, therefore, generation reduction in terms of producing -- having the need to produce power utilizing these same four resources, where we're at in 1997 and where we go to the year 2006, and we're showing gigawatt hours now versus megawatts.

And again, to look at what is the biggest contribution, self-serve cogeneration or qualifying facilities as well as conservation are the main contributors here.

Load management, as we heard earlier, in some cases is somewhat neutral relative to energy reduction, but it does have an effect on some systems, but as you can see from the chart, it's not a significant energy reduction. It's much more available as an operating resource and deferring new generating plant.

COMMISSIONER DEASON: What you're saying is that the main reason for load management is to shift the load from peak to off-peak, but it does have a conservation effect in terms of energy in megawatt hours as opposed to megawatts?

MR. HERNANDEZ: That's correct.

COMMISSIONER DEASON: And that's what's shown in this graph?

MR. HERNANDEZ: Yes, Commissioner.

The next chart reflects the existing generating plant that's located within peninsular Florida by utility, and basically what we're showing is a slight increase in capacity over the winter months. This has to do with thermal efficiencies due to cooling water temperature and ambient air temperature, but roughly we're showing 35,000 to almost 37,000 megawatts of capacity as of January 1 of this year. So it does not include planned and proposed facilities, and the percentages are relative to the total capacity.

Another supply-side resource to consider in calculating reserve margin and looking at the reliability of peninsular Florida is to consider what can be imported as well as exported across the -- our transmission ties to the north. What this chart shows are the relative ratings for both the winter and summer for import capability, which is what we're primarily concerned about in terms of purchases to contribute to reserve margin as well as to meet load, but also the export. The export also has to be considered when you start factoring what is the net amount that contributes to the reserves or to the load in the state.

MR. HAFF: But before you leave that slide, I guess this is a good time to ask this question. What is each utilities' firm share of that transfer capability on import? Do you happen to know those numbers or is that something I should ask each of the utilities?

MR. HERNANDEZ: There are four utilities that have the allocation, if you will, of that interface, and I think it would be more appropriate to ask them what their allocation amount is.

MR. HAFF: Okay.

COMMISSIONER CLARK: Do you know whether that allocation exceeds the whole?

MR. HERNANDEZ: I believe it totals to the 3600 megawatts we're showing as import.

COMMISSIONER CLARK: Do we do much exporting?

MR. HERNANDEZ: I believe -- I'm going to draw on memory for -- in the first year of 1997 plan, we're showing 1650 megawatts firm import and I believe 350 megawatts firm expert, for a net of 1300 megawatts firm import, but again, that would be on a utility-by-utility basis as to who they have contracts with.

COMMISSIONER DEASON: Before you leave that slide, the import capability in winter is 3600 megawatts, and the UPS purchases plus Scherer add to about 2550. What accounts for the difference? Is that unused import capability or is that import capability being used by other things than UPS and Scherer?

MR. HERNANDEZ: It's being utilized by other economic purchases.

COMMISSIONER DEASON: But there is another 1,000 or 1100 megawatts as you're indicating, that can still be imported on a firm basis, but right now it's being computed on an economic dispatch basis. If it were determined it would be available, that would be capacity to serve on a firm basis?

MR. HERNANDEZ: That's correct, economic transactions, broker type transactions, we don't consider those when we assess reliability. So it's not factored in at this point.

COMMISSIONER DEASON: Okay. Is that something that the utilities in the state are generally looking at, the fact that there is apparently some capacity that could be utilized on a firm basis to import?

MR. HERNANDEZ: Commissioner, I still believe that that's more of an individual utility issue. Again, it goes back to who has the allocation of what's available as well as what's going on with the market. That isn't an issue that I believe is -- other than from an operating perspective, is being addressed, nor needs to be at this point from a reliability perspective. It comes down to economics.

COMMISSIONER DEASON: So you're saying each individual utility that has an allocation of that import capability, they just include that in their overall planning, determine what is economic for them, and then that is compiled and then you're just showing the summary data here?

MR. HERNANDEZ: That is correct.

COMMISSIONER DEASON: Who are the utilities which have that, other than Florida Power & Light and Power Corp. that have an allocation of that capability?

UNIDENTIFIED SPEAKER: JEA.

COMMISSIONER DEASON: JEA.

UNIDENTIFIED SPEAKER: Tallahassee.

COMMISSIONER DEASON: And Tallahassee, okay.

MR. HERNANDEZ: This one's a little difficult to make out, but it's simply to represent the contribution to -- on the generation side. So it excludes the effects of conservation but it is intended to show what type of fuel is being used to generate the capacity and the energy that's required to meet our peninsular Florida requirements.

A couple of points to make here is, if you look across, again on the incremental, going from 1997, 178,000 gigawatt hours, to the year 2006, it's roughly 219,000 gigawatt hours. The increment there is roughly 42,000 gigawatt hours, and when we start looking at incremental resources and utilization of resources, I think that, you know, that needs to be considered. You've got to look at existing resources as well as what's being added and how they plan to be utilized.

We're doing this on an aggregate basis, but it really comes down to utilization of those resources are utility dependent, and again gets back to economics and cost-effectiveness.

COMMISSIONER KIESLING: How realistic is it on the 2006 to have almost five percent of the generation from orimulsion?

MR. HERNANDEZ: I missed the first part of your question, Commissioner.

COMMISSIONER KIESLING: How realistic is that projection? I mean it's --

MR. HERNANDEZ: I believe that's what Florida Power & Light is showing in terms of their ten-year plan. To the extent that, if we were to displace that with other fuel, I think that's a Florida Power & Light issue. That is what they showed in their ten-year plan.

COMMISSIONER KIESLING: Okay. Thank you.

COMMISSIONER DEASON: The purchases are increasing as well. Is that increased purchases through import, through the import capability we spoke about earlier?

MR. HERNANDEZ: It's a combination of firm as well as economic purchases. When we start talking about generation, if there's displacement on an economic basis from a resource that's outside the state, if you will, that would be included here.

COMMISSIONER DEASON: Okay.

MR. HERNANDEZ: This next chart indicates the incremental resources which now includes the effects of load management, interruptible customer and conservation programs. Looking at the ten-year period from 1997 to the year 2006, we're using the summer number or summer megawatt ratings here just for reference purposes, but effectively looking at approximately 6,000 megawatts of additional energy resources. So we've got supply- and demand-side resources here.

Looking at the demand-side resource, approximately one-third of the incremental resources to meet our growing state needs will be supplied by DSM, specifically those three areas that I've got on the chart. Combined cycle and combustion turbine seems to be the technology of choice, with some additional import capacity as we just mentioned, relatively little increase in fossil steam, and again, looking at the relatively shorter construction lead times and flexibility that combustion turbine and combined cycle capacity offers.

COMMISSIONER DEASON: Now, this goes back to the question that I asked about the report card. You're doing this on an incremental basis in the sense that is incremental generation and then incremental conservation as a percent of that incremental generation?

MR. HERNANDEZ: That's correct. In this sense, though, we're looking not at one year but over the ten-year planning horizon.

COMMISSIONER DEASON: Now, that category which comprises 32 percent, which is load management, interruptible and conservation, do you know the amount of that which is conservation?

MR. HERNANDEZ: It's approximately just under 1,000 megawatts.

COMMISSIONER DEASON: So approximately half of that 32 percent then would be conservation?

MR. HERNANDEZ: That's correct.

COMMISSIONER DEASON: Okay. Thank you.

MR. HAFF: While we're on that subject, I was going to ask this at the end, but staff -- we're wanting to see what the annual last, I guess, forecasted ten years are of conservation as an aggregate. We don't have that information in the plan, just load management and interruptible. Is there a way we could get that on an aggregate basis?

MR. HERNANDEZ: To isolate the conservation?

MR. HAFF: Correct.

MR. HERNANDEZ: I'd have to check back with the folks at the FRCC, but I'm not sure at this point. I don't have that information available today.

MR. HAFF: Okay. I'm trying to -- who would we ask, I guess, for that, because getting back to what LEAF's report said and some of the questions we've heard here, we'd also like to know what the annual energy savings are as a comparison to net energy for load on an annual basis so we can look at those as well from an aggregate viewpoint?

MR. HERNANDEZ: Okay. I understand the individual utilities have those calculations. I'm just not sure if they're being collected at this point under the FRCC. So we'd have to check on that.

MR. HAFF: Okay. If so, we'd like to get that.

MR. HERNANDEZ: This next chart is -- reflects the projected reserve margins for the summer period and it's broken down into three components showing the firm peak. That is the larger blue bar. The next increment is capacity. That's capacity over and above what the firm peak would be. And then the load management and interruptible.

In this calculation the firm peak has already been reduced by the effects of conservation. So the 1,000 megawatts or so are already pulled out over the years on an incremental basis so that the firm peak has that effect in it, and we're just showing the dispatchable generating resources as well as the load management, and then the calculated reserve margin is shown above each bar.

A comparison of the summer reserve margins to the 1996 ten-year plan aggregate indicates a slight reduction in projected reserve margins, but still adequate, especially over the next five years, and again referring back to the flexibility that utilities have in terms of the type of capacity that we've selected in terms of meeting the growing needs of the state.

COMMISSIONER DEASON: This shows a reduction in the reserve margin for summer peak from the '96 study to the '97 study, and you say that it still is acceptable at least for the first five years. What about the next five years?

MR. HERNANDEZ: I would still say it's acceptable, Commissioner, for a variety of reasons. I'm not sure if you want me to talk about the winter before I get into the adequacy concern.

COMMISSIONER DEASON: Well, the winter doesn't even -- I mean, winter seems to be more critical than the summer. If you've got some generic subjects you want to talk about, we can go ahead and to the winter and then you can discuss it.

MR. HERNANDEZ: Okay. Because that will be the end of my overheads.

A similar chart, again for peninsular Florida, firm reserve margin for the winter now, and again keep in mind that we were showing higher winter peaks. This -- so as an aggregate, we're still showing the state as a winter-peaking system, but certainly we're reviewing what happens over the summer in terms of expected reserves.

A similar story here in terms of how it's represented, declining capacity, available capacity above firm peak and showing the risk margins slightly lower, again attributed to the higher peaks.

MR. HAFF: This really concerns the staff because -- particularly in light of the fact that there's no capacity driving that reserve margin. It's all load management interruptible and, furthermore, it goes below 15 percent, I guess, in three years.

What's the primary cause for the drop to eight percent?

MR. HERNANDEZ: There's -- relative to the calculation, the thing I just mentioned where the higher peaks -- if you'll recall one of my earlier overheads showed the difference in winter peak. The aggregate winter peaks are anywhere from 1600 -- or 1200 to 1600 megawatts higher. So that directly -- that by itself directly cuts into the calculation of the firm reserve margin.

MR. HAFF: Is there any plans to build capacity to meet those increased peaks on an aggregate level? I mean --

MR. HERNANDEZ: If I can go through this last chart, then I'll start addressing those issues and it will complete this part of the presentation.

MR. HAFF: Okay.

MR. HERNANDEZ: This is a similar graphic comparing last year's ten-year plan versus this year's ten-year plan. It does reflect a decrease in both the initial five-year planning horizon and a bigger increase over the last five years, in the five to ten-year planning period.

To address both your comments, Michael, and Commissioner Deason's, first off, we are indicating lower reserve margins for peninsular Florida. What I've mentioned before is that, looking at the incremental resources that are being planned in general, we're looking at gas-fired, oil-fired, combustion turbines and combined cycle units that have relatively lower or shorter construction lead times and permitting times. If you're looking at existing generating plant sites that have already been sited and permitted, in peninsular Florida we have approximately 9,000 megawatts of additional capacity that can be built on sites that are either already sited or permitted or already have new plant.

For example, for Tampa Electric, we got the Polk Unit 1 and the site that was permitted, that was permitted for 1150 megawatts. We put a 250 megawatt combined cycle unit on there. So we've got 900 megawatts of additional capacity that can be constructed at that site. It doesn't preclude the fact that you've got to go in for permitting for a combustion turbine or a combined cycle, and that does have some time, but looking at, for example, combustion turbine, we're assuming a 24-month lead time once we identify the need versus the time that we can put the plant on the ground and be operable, and this story may be a little different, again, on a utility-by-utility basis, but the fact that we have 9,000 megawatts of siting that's already been developed or readily available, what you're looking at are the permitting times on a unit-by-unit basis as well as the purchase time to drop in a combustion turbine and a combined cycle.

At an existing site that's relatively easier to accommodate versus developing a green field site.

MR. HAFF: What about the lead time for adding a new gas pipeline to serve all this electric demand?

MR. HERNANDEZ: The gas availability issue I think is more of an economic issue versus a reliability issue. To the extent that folks are planning to build dual fuel-fired combustion turbines or combined cycle units, you can set up your system to readily have distillate oil or alternative fuel to the extent that the gas and where you get the gas -- that issue can be developed on a utility-by-utility perspective versus looking at this from a peninsular Florida perspective.

MR. HAFF: Well, from a peninsular perspective, most if not all the additions are going to be -- that are in the plan are gas-fired, combined cycled and combustion turbine, and even with the units that are shown in this plan, we're still looking at an eight percent winter reserve margin, and I guess we're just trying to figure out what happens if all of a sudden every utility wants to put these CTs in with 24 months of lead time and there's no gas to serve them. I mean, that's a critical concern we have about the, you know, out years of this plan.

MR. HERNANDEZ: Again, I believe it's more of an economic issue, a cost-effectiveness issue that needs to be addressed by different utilities.

Different utilities are going to have different options in terms of how they secure their gas contracts in order to run these units, but you've got to look at usage of the plant. If someone's looking at a very high load factor for a combustion turbine and combined cycle because that type of capacity is becoming much more efficient, they may be more inclined to firm up gas. If a system is looking at a relatively low utilization of that capacity, then for economic reasons it does not -- it makes less sense to go ahead and firm up the gas because you've got the option to run the unit on an alternative fuel, and to the extent that you do not impact the capacity or the heat rate and it's basically a tradeoff on the cents per million on the fuel choice, it is an economic situation, not a reliability issue.

So to the extent that you've got short construction lead times and relatively shorter permitting times for the 9,000 megawatts or so of existing site that I've mentioned before and the fact that it really gets down to a utility-by-utility analysis, I'm not concerned about showing lower reserve margins in the out years.

Looking at the first five years in both the winter and summer, I believe we are -- we do have adequate supply resources, planned and proposed, for both winter and the summer, and we have the flexibility for each utility to address those issues down the road.

COMMISSIONER DEASON: What I hear you saying is that we don't need a ten-year site plan, we need a five-year site plan?

MR. HERNANDEZ: I'm not suggesting that.

COMMISSIONER DEASON: Well, what you're saying is we've got these projections for ten years, and it's unacceptable in the later years, but you're telling us, don't worry about it because we have enough sited area, locations, and we have short lead times, short construction times, so there's no need to worry about the later years.

As long as we've got things covered for five years, we're okay. That's what I hear you say. Now, if that's not what you're saying, correct me.

MR. HERNANDEZ: Generally that's correct, and the reason I think we're okay in saying that is, looking in years past where other generating plant that had longer lead times -- for example, a fossil fueled, base load coal unit has a much longer, eight to nine year, construction lead time, let alone nuclear. So I think, relative to individual utility planning, you've got to have a much longer look. You've got to look at different options and different alternatives under different scenarios, load growth assumptions, capital cost assumptions.

I guess what I'm saying is, given the fact that looking at the next five years and the expandability that this state has to drop new generating plant that's very efficient, absent of the gas availability issue, which I think is, again, utility specific, that we're okay to show in the long term smaller reserve margins than we have in the past.

To the extent that folks -- the economics turn around and folks are looking at technologies that have much longer lead times, that's why you want to look at a ten-year plan.

COMMISSIONER DEASON: Well, let's look at the fifth year, and I'm looking at the winter reserve margin year 2001 and 2002, that winter. It indicates 11 percent with a minuscule amount of actual generation capacity above the projected winter peak demand. Is that acceptable?

MR. HERNANDEZ: Again, this is an aggregate, and it's difficult to assess what the impact would be on any individual utility, but --

COMMISSIONER DEASON: No. What you need to -- I'm going to be very polite, but what you need to realize -- you're sitting there saying, "Well, this is an aggregate and each individual utility needs to make economic decisions" and all that. That's fine and dandy, but this commission has the responsibility to make sure that there is adequate capacity for the entire state, not each individual utility, and it's not going to do a lot of good if one utility has adequate capacity and another doesn't and there's no way for there to be sharing of that capacity, and when there are brownouts and blackouts and things of that nature, that's where the rubber meets the road and that's where we have failed in our responsibility. Do you agree with that?

MR. HERNANDEZ: I agree that that is your responsibility.

COMMISSIONER DEASON: All right. Now, perhaps I interrupted, and I apologize. Is what is shown there at 11 percent acceptable in the year -- in the winter for 2001 and 2002?

MR. HERNANDEZ: I would say yes, and the reason why I would say yes are two-fold. Again, it reflects back that we have the potential -- in looking at what's happening with the market in Florida -- and, again, we're focusing on the winter peak. If you go back over the past -- let my divert just a second. If you go back over the past five years, we've had relatively mild winters. Except for the '95-'96 winter, we were pretty much 1,000 megawatts or so below forecasted peak, and again, just to reiterate what I've said before, this does not account for load diversity. This is a compilation, just a simple adding up of all the loads in the state. So you've got load diversity across the state that could account for a further reduction of four percent -- four to five percent, if you look at time of use and time of system peak. So that's another piece that --

COMMISSIONER DEASON: Now, let's talk about the load diversity. You're saying this is a compilation and that this is each individual's forecasted winter peak, and then when all added to -- actually when the winter peak occurs, it's probably not going to be as high as each individual utility's forecasted peak because there's going to be some diversity in that?

MR. HERNANDEZ: That's correct.

COMMISSIONER DEASON: Now, it seems to me that when we have a really severe crunch on energy demands in Florida is when a cold front comes through Florida and goes all the way down to Miami, and that's just about the entire state, and it's not going to be a situation where it's going to be warm in Fort Myers and cold in Miami. It's going to be cold in Fort Myers and cold in Miami, at least in the winter situation.

Now, I can understand in summer peaks, when you have a really hot spell, you're probably going to have some areas of the state that are going to have some thunder showers. They're going to be cooler and there's going to be less demand, but you don't have that in winter, unless there's something I'm missing. So please educate me.

MR. HERNANDEZ: Again, it's directly attributed to the weather, and if we have a cold snap that comes across the whole state, then I agree with you, but often that's not the case. It has happened in the past. Christmas '89, you know, that did happen. We had a cold snap over several days, and what happens is you do exactly what we're showing: You implement load control. You go to your non-firm load resources, and that's what we're showing, again, in that fifth year, that you're at that point where you're down to just -- well, it's less than one percent of capacity that's on the ground, but the good thing is, in terms of looking at, again, the --

COMMISSIONER DEASON: And here again, I hate to interrupt, but that one percent of capacity on the ground, is that all capacity that is projected to be available at that time, realizing that some units are going to be down perhaps for maintenance and some are going to be down on forced outage, or is that everything that we have on our books, it's assumed that it's up and running and ready to respond when that cold snap hits?

MR. HERNANDEZ: This calculation accounts for expected outages or units that are on reserve, reserve standby or long-term reserve standby. It does not account for forced outages. I mean, that's the whole point of having a reserve margin is to have that flexibility to cover variances in load as well as variances in available capacity. This also does include all the firm contract capacity purchases, both on a -- well, from a statewide perspective, what you're concerned about is what's coming across the interstate --

COMMISSIONER DEASON: Would you agree that at least in the history of the -- was it the '89 freeze or whenever it was -- that the fact that we had some extremely cold weather seemed to have some impact on the fact that there were going to be some forced outages? Things happen at power plants that -- when it gets really cold, that you don't really normally anticipate and perhaps could trigger an outage at a plant that would normally not have occurred?

MR. HERNANDEZ: That's correct, those things do happen. But again, I go back to, that's why you carry a reserve margin. To the extent that reserve margin is made up of a mixture of supply-side and demand-side resources, I think at this point -- again, looking through the five years, I think 11 percent, with a significant piece of that 11 percent as being load management and not firm load, is acceptable at this point. And again to stress the fact that over the next couple of years, if we continue to see or expect that peaks are going to be at what we're showing right now in this plan, then we have the flexibility and adaptability to recover and put plant on the ground sooner, and again I think that's --

COMMISSIONER CLARK: What was your time frame again for putting a plant on the ground?

MR. HERNANDEZ: A combustion turbine at an existing site -- and, again, this would vary, utility-specific, but approximately six months for permitting and 18 months to select a vendor and drop it on an existing site and tie it into the facilities that are already there. That would be short end, two years, 24 months.

Combined cycle, 36 months is what we're assuming at an existing site.

COMMISSIONER CLARK: Aren't you also assuming the utilities will build it?

MR. HERNANDEZ: I'm sorry?

COMMISSIONER CLARK: Aren't you also assuming that the utilities will build it?

MR. HERNANDEZ: In this scenario, we are not -- we're only including what's planned and proposed.

COMMISSIONER CLARK: Let me ask it a different way. To the extent you push the envelope and you wait as long as you can, you diminish your options and you will be -- the utilities will be the only entities that have a site permitted, so they'll be the one who puts up the plant.

MR. HERNANDEZ: Versus other market entrants?

COMMISSIONER CLARK: Yes.

MR. HERNANDEZ: But I guess I would --

COMMISSIONER CLARK: Is that correct?

MR. HERNANDEZ: I would say, if we have 9,000 megawatts of site, and to the extent that the market supports other new market entrants into the state and they're accessing or have access to that site -- again, that's not a utility-by-utility basis -- I can't say it would just be the utility building the plant. There may be the emergence of other energy providers or generators in addition to a co-generation facility that's not planned right now.

COMMISSIONER DEASON: But I think what Commissioner Clark is suggesting is that we're going to -- if we find ourselves -- if the projections go out in a way -- perhaps the demands increase more than projected and perhaps other things happen and we get into really a crunch, that we're going to be in an emergency situation and that the only alternative is going to be for the utility to build something on their site and do it in 24 months, and you can't go through a competitive bidding process because the time doesn't allow it, and then do we respond that we are meeting our obligation to ensure that least-cost sources of supply are actually being generated or being constructed?

COMMISSIONER CLARK: That's exactly right.

COMMISSIONER HERNANDEZ: I would agree with what you're saying, but I would say that that's more -- it again goes back to a utility-by-utility basis. In the aggregate, at this point, I think we're okay.

COMMISSIONER CLARK: That's not answering the question. To the extent you push out as much as you can putting off building it, you limit who has the opportunity to build it, and the utilities are in a much better position because you already have permitted sites.

Do you know of any independent power producer that has a permitted site it can use?

MR. HERNANDEZ: I'm not aware of any, no.

COMMISSIONER CLARK: I'm not either.

MR. HAFF: I'd just like to jump in. What Leslie passed out a few minutes ago was a projection of capacity, demand and reserve margin from the 1989 APH hearing, which was the last statewide planning hearing that we had, and the second page shows winter reserve margin, and I'd just like you to note the level of reserve margins that the peninsula was projecting to carry at the time, and particularly I guess it was the first or second line, the Christmas freeze of '89, we were projecting over 25 percent reserve margin, and so, you know -- and like you, I question the reasonableness of 11 percent.

And I guess another question I had was the plan to build CTs in a short lead time to drop them into existing sites, if there's no gas, you're saying that you're going to burn oil as a contingency, are you not?

MR. HERNANDEZ: That's correct, at least for Tampa Electric. That may be different for other utilities.

MR. HAFF: Okay. Do you feel like the fuel adjustment clause should allow you to continue to recover those costs?

MR. HERNANDEZ: I guess -- why not?

MR. HAFF: You know, we're -- you know, we see in the plan the reserve margins, and you've shown the Commissioners the reserve margins. We haven't had a peninsular or statewide loss of load probability study in a number of years, and we -- the staff is not comfortable. What amount of reserves for this state would be equivalent to a, you know, one-day-in-ten-year loss of load probability. For example, in the past, it was a lot higher because units were not as reliable as they are now, and I guess what we'd like to see is, you know, an LOLP study for peninsular Florida to, you know, give us some comfort that these reserve margin numbers, as you say, are acceptable. I don't have any comfort at all and I don't think any of the staff does.

MR. HERNANDEZ: Well, along the lines of what is an appropriate reliability assessment criteria, you referred to the 1989 APH. At that point in time, as a state when we were doing the -- really running models on the state, we had used the 0.1 assisted loss of load probability. Through time we moved away from that in terms of making that assessment because there are a lot of complex issues in terms even assessing that calculation for the state.

The reserve margin calculation is straightforward, relatively straightforward to assess assisted loss of load probability. There's a lot of other factors related to transmission, operating issues. You get into effectively having to -- modeling the available resources across the ties to the north, and that's -- in a competitive age, that's very difficult to have that information available, not only within peninsular Florida, but outside that, to effectively -- you've got to know loads. You've got to know unit availabilities. You've got to know maintenance outage schedules. There's a lot of things in order to calculate an assisted loss of load probability, and I think where we're at from an FRCC perspective is -- and perhaps Henry Southwick could address that in a little more detail, but we've formed a working group, a reliability assessment group that's going to further address this issue and try to identify what are the relevant issues that need to be considered in assessing the reliability of peninsular Florida in the aggregate.

COMMISSIONER DEASON: So, are you saying that, because of changes in the industry and the shadow of competition, that a peninsular Florida loss of load probability study is -- can't be done?

MR. HERNANDEZ: Very difficult, and it goes beyond just sharing information within the state. You also need to -- because it's an assisted loss of load probability, the amount of capacity, supply-side capacity that's available across the ties is important, and so you've got to share information or obtain information that also assesses the adequacy of a neighboring region that's going to provide that support over the ties.

COMMISSIONER DEASON: Okay. Now, you've got firm capacity for a lot of that tie line capacity, right?

MR. HERNANDEZ: That's correct.

COMMISSIONER DEASON: Okay. Now -- so then you're talking about availability of generation in excess of what is already on a firm basis?

MR. HERNANDEZ: That's correct, again, for emergency reasons, not economic. And again, to even address if LOLP is the appropriate criteria, there are other measures of reliability that need to be considered or should be, and not just move back to a 0.1 assisted LOLP.

COMMISSIONER DEASON: Well, what are the other criteria that can be utilized other than loss of load probability and reserve margin, because you've got staff saying they don't think this -- your reserve margin calculation's good enough?

MR. HERNANDEZ: Well, just for example, expected unserved energy is another indicator that -- in fact, it's one that Tampa Electric has now adopted that captures both magnitude and frequency because it's expected unserved energy gigawatt hours. Loss of load probability only gives you the frequency it. It doesn't tell you how short you're going to be in terms of capacity. You can be one megawatt short or you can be 1,000 megawatts short. It's still a loss of load probability.

So that's just one example, but I think a lot of these things are going to be discussed at the FRCC to try to get a better handle on this.

COMMISSIONER DEASON: Well, you indicated an expected unserved energy. Is that something -- it seems to be even a more detailed and precise calculation than the loss of load probability. How is that -- how can you perform that on a peninsular basis if you can't do the LOLP on a peninsular basis?

MR. HERNANDEZ: It's similar to the extent that it has some data requirements but not nearly as much. To the extent that you've got to factor in generation available at the time when the load requirements are, that has to be determined somehow, and I think all -- a lot of this has to get fleshed out at the FRCC and the couple of the working groups that they've formed to further identify how can we do this.

Again, with other market entrants as another issue, you know, you've got to be able to have access and -- to information, and I'm not sure to what extent that new market entrants are going to provide that information.

What are their plans? Do we know what their plans are? Are they going to build capacity? Was is their intent?

A lot of that has to get factored in in order to do an EUE calculation or a loss of load probability. Who plans to build and when?

MR. HAFF: I was just going to say that I understand the FRCC can't get this utility-specific data to do an LOLP study or an EUE study or whatever because the utilities aren't sharing it. You know, what comfort do we have in what you're telling us?

MR. HERNANDEZ: Henry Southwick just joined me. Henry is the chair of the engineering committee of the FRCC, and I'll ask Henry to help.

MR. SOUTHWICK: Well, I don't have any magic answer, that's for sure, but what we are committed to do is to sit down at the engineering committee and attempt to get the answers, because I don't know if LOLP or unserved energy or percent reserve or whatever it's going to be, and things that worked ten years ago may not work today, and what we intend to do is we've formed this new group that Tom mentioned, called the Reliability Assessment Group. We only did this at our last meeting. We have reactivated our Resource Working Group, which used to be called the Generation Task Force several years ago, and we're going to address these issues.

MR. JENKINS: But, Mr. Southwick, the fundamental question is, because -- performing an LOLP or an EUE reliability study is perhaps beyond the question because doing so results in utilities sharing market-sensitive information with each other, is that correct?

MR. SOUTHWICK: Joe, we really don't know until we try. There may be a problem. There may be. I suspect in the latter years it will be a lot bigger problem than in the earlier years when things are more certain.

MR. JENKINS: And you have not done a peninsular probablistic study of reliabilty since roughly 1988 or '89, is that correct?

MR. SOUTHWICK: Yes.

MR. JENKINS: And, again, it's the market-sensitive information that seems to be delaying things?

MR. SOUTHWICK: I think it was those forces that caused it to stop happening, and what we're going to have to do is try to piece it together as best we can in the new world.

MR. JENKINS: Have you considered taking the FRCC and giving it a permanent staff to perform reliability studies in which market-sensitive information can be kept confidential within this FRCC staff and not use a task-force, representative type of structure?

MR. SOUTHWICK: Have we considered it? No, not to my knowledge. It's an idea.

COMMISSIONER CLARK: Let me follow up on that.

Who currently serves on the Florida Reliability Coordinating Council? Who's part of that group?

MR. SOUTHWICK: I believe all the utilities in Florida are members, as well as several power marketers.

COMMISSIONER CLARK: And who are those power marketers?

MR. SOUTHWICK: I'll have to get some help. One minute, please.

COMMISSIONER CLARK: Well, while he's looking for that, Mr. Hernandez, do you know the balance of it? I mean, is it more power marketers than there are utilities or more utilities than power marketers.

MR. HERNANDEZ: I don't know.

MR. SOUTHWICK: Let me introduce Ken Riley, who's the executive director of the FRCC.

MR. RILEY: Commissioner Clark, we have about 31 or 2 members at the present time in FRCC, and about 19 of those -- 20 of those would be traditional utilities as we have known them. So we have quite a few power marketers on board, and I expect a couple of IPPs to come on shortly, and we have some outside electric utilities from other states.

COMMISSIONER DEASON: Have you given any thought to Joe's question about having on staff to do these type of studies and get information on a confidential basis that their and your staff would report to you or the association and not have their primary job being for one of the utilities or power marketers?

MR. RILEY: Joe, I appreciate you helping me build my staff up. Being staff, we always try to do that because we never have enough; but I would like to respond to that by saying that within FRCC as we know it today and in the operating arena, we share through FRCC some -- what the utilities consider some highly confidential information, such as, when are utilities going to be taking their generating units out for maintenance purposes, you know, when does it go out, when it's coming back in and et cetera, because we need to coordinate our maintenance programs to make sure that our reserves, as we go through the next 12 months, are in fact adequate every week of every month, and this information comes in from individual utilities that own generation, and we massage it at the staff level. We evaluate it and we send the conglomerate, the total out to everybody to look at so that they can see what it looks like statewide, but they're not privy to other people's confidential information.

Now, we have one or two individual utilities that are -- have personnel that are responsible to FRCC to perform certain activities, such as the security coordinator in the state, and that person is an agent of FRCC, and we give that agent this -- all of this individual information, and he basically has signed a confidentiality agreement that says he's not going to disclose it to any of his marketing people or to any other marketing people.

So I think that we have a mechanism to solve this confidentiality problem when it exists.

COMMISSIONER DEASON: Well, what I hear you saying, it seems to me that that is in place, seems to be working, but it's more of a short-term nature. It's how do you plan so that everybody doesn't go put all their units on maintenance on the same week of the year and we don't have enough capacity? I mean, obviously that is a very vital function that's got to be performed, but I think what we're concerned here is on the longer term, not necessarily the scheduling of maintenance and that sort of thing, but when a new unit needs to be constructed, and if there's any assessment on a peninsular basis on the longer term looking at loss of load probability or expected unused energy or whatever it is to give information as to when additional capacity needs to be constructed in the state.

MR. RILEY: I feel that, if we do prove that in this new environment we're working in that LOLP or unexpected load or whatever the mechanism that you're using can be done, and the technical ability to do it is there. I think that we can solve that through our existing organization of FRCC, bring that information in and keep it confidential on an individual basis and report the results, if that is what we need to do; and as Henry indicated, we have a group formed right now that, as soon as this workshop is over today, we're going to be sitting down and discussing what it is we as the FRCC feel that we want to do. And let's surmise that the results of our deliberations, of all of our experts are that we don't think that we ought to have loss of load probability on a statewide basis -- let's just assume we come up with that determination. You know, if your staff continues to feel that this is something that we need and they're convinced otherwise, well, I think that we've got to work that out with the staff, and I know I've been talking with your staff a little bit and we would welcome the Commission to continue to send your staff to all of our meetings like this, especially our Reliability Assessment Group, to hear our deliberations to provide input if they would like and so that, if they feel that we're heading off in some direction that is not acceptable to this commission, we want to know it then, not a year or two down the road after we have done something and --

COMMISSIONER DEASON: Well, let me say that I certainly encourage staff to participate in any way that they see fit and that you want them to participate, and I'm glad you're looking at this. I think it's something that needs to be looked at. I think it's something, though, that the industry needs to deal with because, if you don't, what is the alternative? That means that we're going to have to do it or try to go to the Legislature to get an appropriation to put our own planning staff in effect, and you know how things are done when you try to do planning at a state level. I think then it's -- but something's got to be done if we are not convinced that you are addressing the problem, and I think what I'm saying -- and I don't want to speak for the other commissioners, but I don't want this commission to become the planning agency for the construction of electric utility generation in this state. I think that should be the responsibility of the industry. It squarely should be on your shoulders, and you're probably more capable and have a very high vested interest in it; but you need to realize it and need to do it and give us satisfaction that the planning is taking place and that there is sufficient whatever it is, whether it's loss of load probability that's a sufficient cushion or reserve margins or whatever it is, and can show us summary information.

I'm not so sure that we even need to look at the confidential information that each individual provides to you if you can certify to us that it is an accurate compilation of all that information and that the proper mathematical and statistical and engineering analysis has been done to substantiate the results, but I think that we're perhaps at a crossroads in this planning process and I think we need to decide what we're going to do and we need to make decisions now that hopefully are still going to have the industry take care of that, and hopefully this commission or some other state agency is not going to start meddling in your affairs and dictating -- doing your planning for you and telling you when, where and how you're going to build an electric generating unit. I don't think that's the direction any of us want to go.

MR. RILEY: I think our industry, through FRCC, will handle this thing, Commissioner Deason, and this -- it's our new industry. FRCC is just not the electric utilities as we know them. We are trying to ensure that our -- all elements of our new industry are involved in this process. So I think that we would -- we'll prove to you that we will rise to this challenge.

MR. HAFF: Ken, did I hear you say a few minutes ago that you can or cannot perform some sort of probablistic study of the peninsula LOLP or expected unserved energy or whatever? Did you say it couldn't be done, it possibly could be done?

MR. RILEY: Michael, I was following up on Tom's comments a moment ago where he indicated that we need to look at some of the new environments to see how we used to do them and does it still fit with the modern-day players? And I'm not enough of an expert on that anymore to be able to comment, but -- so I was just alluding to Tom Hernandez's comment on that.

MR. HAFF: Okay. Well, Tom, you know, do you know if we could see one of these, the results of one these studies by, say, internal affairs when we take our review down in December? Is that something that could be done in the time frame?

MR. HERNANDEZ: I believe that we've got the technical capability and the expertise and the understanding, but I think, Michael, we still need to discuss this at the FRCC and allow this reliability assessment group to go through this before I respond. I'm going to participate with that group, have an interest in addressing all of the commissioners' issues, but we need to do it as a group, and I don't want to speak for the group prior to meeting.

COMMISSIONER CLARK: Commissioners, I should probably indicate that you probably know that I am now the

NARUK representative on NERC, which is sort of the next level up, and they are the entity that in fact allowed Florida -- approved Florida coming up with its own reliability coordinating council.

I have to say my schedule hasn't allowed me to go to that first meeting, and I would hope that I would get more information about how this can be handled because I know one of the issues has been what they call tagging. In some areas they want to know where are you getting the power from and where it's being wheeled to, you know, so that they can do an assessment of whether it's reliable and that sort of thing, and the entities, the power marketers are unhappy because they figure what will happen is then the customer, the ultimate customer will see where it first began and they'll cut out the middleman. So there are issues of how do you mesh both long and short-term reliability with a competitive market?

MR. HAFF: And adding to the concern you just raised, our understanding is part of this eight percent winter reserve margin in the out years is built on purchases from power marketers. Who knows, one day it may come from out of state, the next day it may not, and --

MR. RILEY: I believe that the numbers that you're looking at there from imports into the state of Florida that make up that eight percent are firm contracts that the utilities currently have. There is nothing in there -- in that number dealing with out-of-state with one exception, and that's perhaps 30 megawatts of capacity that we're not sure about.

MR. HAFF: Okay. Is that from Gainesville?

MR. RILEY: Yes.

COMMISSIONER DEASON: And let me interrupt for just a second.

As we indicated from the handouts, and I'm looking at -- apparently it's un-numbered. It's two pie charts, and at the top it says "Peninsular Florida Generation by Fuel Type," and then in parentheses it's got "(Gigawatt Hours)." It's 1997 and 2006. It looks like it's a little bit more than halfway through the packet.

All right. We see purchases going from 7.7 percent to 10.3 percent. Is that going to be an increase in firm purchases of that magnitude, or in there is assumed that there are going to be purchases of a different type other than firm?

MR. HERNANDEZ: If he didn't say it before, I meant to. That includes economic transactions where, if you've got the ability or plan displace existing capacity that you have but actually serve it out of lower-cost capacity, that's included. So broker type transactions across the tie lines are included for the generation.

This isn't so much a reliability issue as just an usage of resources.

COMMISSIONER DEASON: Okay. I understand that.

Now, the increase from 7.7 percent of the '97 total generation to 10.3 percent of 2006 generation, which is a substantial increase, is that increase primarily driven by assuming that there's going to be more economic transactions or is it that there's going to be more firm capacity purchased and imported.

MR. HERNANDEZ: A little of both.

COMMISSIONER DEASON: A little of both.

MR. HERNANDEZ: But it does exclude any other additional power marketing transactions. That is not factored in here. This is just firm capacity and existing transactions or planned transactions between existing entities. It precludes the fact that there may be other market entrants that may displace some other generation by resources here.

COMMISSIONER DEASON: All right. Thank you.

CHAIRMAN JOHNSON: Any further questions?

MR. JENKINS: Yes. Mr. Hernandez, just on behalf of staff, we would like to have by December 1st, in time for the internal affairs final report on this ten-year site planning process, either an LOLP study or an EUE study or, if you cannot do it because of competitive, sensitive information, a letter from you stating explicitly that it cannot be done by December 1st.

MR. RILEY: We'll address that. We'll address that, Joe.

MR. JENKINS: Okay. Thank you.

CHAIRMAN JOHNSON: Okay. Thank you. Thank you for your presentation.

MR. HERNANDEZ: Thanks for the additional time.

CHAIRMAN JOHNSON: We will take a ten-minute break before beginning with Florida Power & Light.

(Whereupon, a recess was had in the proceeding.)

CHAIRMAN JOHNSON: Florida Power & Light.

MR. ADJEMIAN: Good morning. My name is Bobby Adjemian, spelled A-d-j-e-m-i-a-n. I'm manager of resource planning and I represent Florida Power & Light. I'll be happy to be the first utility addressing our ten-year site plan, and I will give you a brief overview of the highlights of our 1997 ten-year site plan.

The overview will review -- will cover the changes in our assumptions, the key assumptions between the 1996 and 1997 ten-year site plans. I'm going to discuss the content of our resource plan and our changes to the projected system fuel mix compared to what last year's fuel mix was, and then I will conclude with the projection of our summer reserve margins.

In 1996, our site plan presented a 2003 need, but since then there have been two key-assumption changes. One had to do with the load forecast which tended to move the need up, and the other one had to do with our unit availability of our fossil fleet of generation which actually is projected to get better and countered the effect of the first forecast or the first assumption change, however, not enough to where we're concluding with a -- it's hard to read this, but the acceleration of need moves to 2002 from 2003.

The content of our resource plan is that, between the period of the next ten years, we are anticipating of adding supply-side resources total totalling 1632 megawatts, comparing it to last year's plan, a ten-year window shifted in time, obviously, by one year. We're adding 1690 megawatts, approximately the same amount, and the breakdown of megawatts are shown in the table below. The 1997 actually on that slide refers to the 1997 ten-year site plan. It's the total of 1632 megawatts, which is met primarily by additions of proposed new units of combined cycle, vintage technology and power purchases. Our -- I should add that --

COMMISSIONER DEASON: Let me -- can you go back to the previous slide there?

MR. ADJEMIAN: Yes.

COMMISSIONER DEASON: The 357 megawatts of unspecified purchased power that's being proposed, is that unspecified because you don't know, or is that unspecified because it's confidential?

MR. ADJEMIAN: It's specified to the extent that we know how many megawatts we need. It's unspecified as to who the originator or the supplier of the power would be.

COMMISSIONER DEASON: And it's because you don't know yet or because you're contracting with or you're negotiating with someone, or you don't want to divulge what you're looking at for competitive reasons?

MR. ADJEMIAN: The need -- the first year need is in the year 2002, and we're looking at purchasing short-term power which we expect that we don't have to right now begin discussion and negotiations, however, I would think that maybe by early next year we would want to do that in order to address part of Commissioner Clark's concern, which is we want to give -- we want to preserve adequate lead time in case those discussions point to purchases that do not make sense to us for our customers, so that we could actually turn in and, if we needed to build a plant, we would build a plant.

COMMISSIONER DEASON: Now, when you say "purchased power," are you talking about purchasing power like importing it from Georgia, or are you talking about purchasing from an independent producer, or both of those could fit in that category?

MR. ADJEMIAN: Yeah, both of those. At this point Florida Power & Light -- if I can reference at least mentally the slide that Tom Hernandez had put up that showed the transfer capability into the state on the transmission tie lines, FPL, as he mentioned, has allocated a part of that 630 megawatts total transfer capability. Our allocation is a little over 1700 megawatts, of which 1500 is currently taken up through the transmission of Scherer No. 4 power and our UPS purchase from Southern Company. So we have about 200 megawatts still available to ourselves. The remaining amount would be purchased from one of the other four users, or three users, I guess, if it's coming from outside the state. However, we see a lot of increased activity within the state in terms of construction of new power plants, perhaps from emergent suppliers, so that the possibility of getting some of those megawatts from within the state, that's also available to us.

MR. HAFF: I don't think from the previous discussion that we're seeing any available capacity from other utilities in the state in the future. Is that correct?

MR. ADJEMIAN: From other utilities, perhaps not;

however, I was referencing emergent power suppliers. For example, one case in point is the plant that's being considered outside New Smyrna Beach, a 250 megawatt combined cycle unit as I understand it, that --

CHAIRMAN JOHNSON: You're going to need to speak into the microphone.

MR. ADJEMIAN: I'm sorry. I was addressing the -- that, unlike -- I was not really specifically discussing utility generation, available generation, although we can talk about that if somebody has some, but I was thinking that -- perhaps emergent suppliers, such as Pan Energy's 250 megawatt that they're at this point considering for early installation I think in the 2000 to 2001 time frame.

MR. HAFF: Now, this 357 megawatts of unspecified purchased power, my understanding is that is included as a resource in calculating your reserve margin, correct?

MR. ADJEMIAN: Yes, it is.

MR. HAFF: And that the FRCC, when doing their peninsular assessment, does not include this because it doesn't know the origination point of the sale?

MR. ADJEMIAN: That's what I understood Tom to say this morning.

MR. HAFF: Okay.

MR. ADJEMIAN: I also wanted to make one additional comment on this particular slide. It's right at the bottom of the slide. I was only discussing supply-side resources. We are including in our resource plan the DSM goals for Florida Power & Light. So that is in addition to the 1632 megawatts. Our resulting fuel mix, I'm showing on the left the 1996 actual 2006 projected.

The primary change that's worth mentioning is that oil consumption is expected to go -- to be halved and be made up by orimulsion fuel. We also see a little bit of an increase in the gas in the mix because of the combined cycle units that are currently in the plan.

COMMISSIONER DEASON: Let me ask you the question. I mean, it was being alluded to earlier -- Commissioner Kiesling asked the question about orimulsion, and your projection is that in the year 2006, ten percent of your generation will be from that fuel source. What's the basis for that projection?

MR. ADJEMIAN: Well, as you probably know, we had began the process of incorporating orimulsion in our system a long time ago before we even came to the Commission in '94, and since then we've had the plan -- or the Siting Board denied FPL's project, and we have -- we've appealed that decision and it's been sent up to the Siting Board, which is voting on it, as I understand, early next month. I'm hoping that the decision will be favorable to Florida Power & Light.

FPL has taken some additional steps since the last vote that we hope will address some of the concerns that were expressed at the time the original vote of the Siting Board was taken. It's -- in our view, this is -- and in my personal view, as long as I've been in Florida Power & Light, which is close to 13 years as a planner, system planner, in essence, it's a project that's producing the greatest benefits, economic benefits to our customers from anything else I've seen. So I hope and it's our hope that that project will be successful and we'll be able to proceed with it.

COMMISSIONER DEASON: Do you have a contingency plan if the orimulsion option is precluded?

MR. ADJEMIAN: Well, we are looking at other refueling options, but none of them are as successful as orimulsion in terms of effectiveness.

COMMISSIONER DEASON: Well, does it -- I know this is a fuel mix projection and it doesn't necessarily -- is exactly equivalent to reliability in terms of capacity, but do -- if orimulsion were not an option, would that affect your plans as far as the effects it could have on your reliability in the year 2006?

MR. ADJEMIAN: Very little, and actually in a positive way, if I may say that, because the plant requires -- after conversion, in order to meet the environmental requirements of the plant, we're including a lot of pollution control equipment which would in essence drain some of the power of the plant. So if we don't do that project, obviously those megawatts are not going to be lost. I mean, we're not talking about significant megawatts, but for all practical purposes, reliability is not really going to be impacted by that plant.

MR. HAFF: And if the conversion turns out not to be an option, are you going to re-power Manatee with natural gas or using natural gas?

MR. ADJEMIAN: I was unaware of that, but --

MR. HAFF: I'm just asking you. I don't know.

MR. ADJEMIAN: Oh, I see. I'm sorry.

Well, as I said earlier, we are considering other refueling options, probably more with solid fuel rather than gas, but --

MR. HAFF: But Manatee right now is burning what, pet coke?

MR. ADJEMIAN: No. Manatee right now is burning residual oil, fuel oil.

MR. HAFF: Okay.

MR. ADJEMIAN: So a potential refueling option may be a conversion -- well, not necessarily at Manatee, but maybe another plant -- converting a plant that burns oil to either pet coke or coal.

MR. HAFF: I'm just trying to continue on Commissioner Deason's concern about where will this ten percent of orimulsion generation come from if it's not orimulsion, and it kind of -- if any of it's gas, that raises further questions. The 35 percent now you're showing in ten years is going to come from gas. Where is it going to come from? How are you going to get the gas? You know, do you have plans for --

MR. ADJEMIAN: So your question is more to the gas rather than --

MR. HAFF: Well, that, too. I mean, there really is two of them.

MR. ADJEMIAN: All right. Well, let me take the first one. I mean, if we find that the orimulsion cannot take place and if we find that any of our other refueling options we're looking at that are on our system do not make sense, economic sense, what you would have is in essence a replacement of that portion of the pie chart by a combination of oil and gas, probably more oil, less gas.

Now, if you have -- I guess your second question was going to, where is gas going to be supplied from? I don't know if we have any Florida Gas Transmission people here, but I can tell you my knowledge of what the capabilities of the gas pipelines are. I have -- as I understand it, currently with Phase 3 gas, we're close to one and a half billion cubic feet a day capability and --

COMMISSIONER KIESLING: Would you talk into the mike?

MR. ADJEMIAN: I'm sorry.

COMMISSIONER KIESLING: I'm losing you the more you turn that way.

MR. ADJEMIAN: I was discussing the capabilities of the current pipeline, what they call the Phase 3 expansion of the pipeline, and I've been told that Phase 4 expansion, which is an additional 500,000 cubic feet a day, is possible with relatively small improvements to the current pipeline, mainly looping and maybe some compression, additions on the current pipeline.

MR. HAFF: How many megawatts of electric generation will that serve?

MR. ADJEMIAN: That -- well, a new combined cycle unit of 400 megawatt size I believe would require between 50 and 60,000,000 cubic feet a day, so you're talking maybe about 4,000 megawatts of generation if Phase 4 takes place, and then further Phase 5 is also available, and I think that would be also an additional 500,000,000 cubic feet, but as I understand, the expansion of Phase 5 is not quite as simple. It may require a little bit more pipeline construction, but at least this is what we have been told by Florida Gas Transmission, and if somebody's in this workshop maybe from that company can -- may be able to address this better.

MR. HAFF: Okay.

MR. ADJEMIAN: My next slide is FPL's projected summer reserve margins, and it's pretty hard to read this, for the audience, but the number levels out at around 15 percent. There are some years of 16 percent, 2004 and 2005, which is our minimum criterion for our power system reliability is a 15 percent reserve margin in the summer.

MR. HAFF: Okay. I have a few more questions.

Now, I understand that that includes the addition of the unspecified capacity that we discussed earlier.

MR. ADJEMIAN: That's correct.

MR. HAFF: Okay. And if that -- you know, subtracting that unknown source out of there, you're going to drop below 15 in a few of those years, right?

MR. ADJEMIAN: Subtracting it, yes, obviously, will reduce that portion.

MR. HAFF: Do you know how that would impact -- you use LOLP as your probablistic criteria?

MR. ADJEMIAN: Yes, we use that as well. We'll look at loss of load probability, but we use 15 percent as the minimum required reserve margin. So even if loss of load probability tells us that we have adequate generation, yet reserve margin's below 15 percent for the summer, then we will add capacity appropriately to meet the 15 percent.

MR. HAFF: Okay. And I'm assuming the base plan is going to meet your LOLP criterion or else you'd be building more?

MR. ADJEMIAN: Correct.

MR. HAFF: Okay. Does your LOLP -- do you know, if you fail that criterion, if that unspecified capacity that is in your plan -- if that is taken out, what would we be the impact, do you know, or have you modeled that?

MR. ADJEMIAN: On the LOLP itself?

MR. HAFF: Yes. I mean, do you fail your LOLP criteria if you take that out?

MR. ADJEMIAN: I couldn't tell you that. I don't see why I would want to take it out, but I have not --

MR. HAFF: Well, because we don't know if it's -- if it's coming from inside the state, then we still have an eight percent peninsular reserve margin.

MR. ADJEMIAN: Well, we have a 15 percent reserve margin.

MR. HAFF: Well, that's the summer. The winter I show you dropping below 15 percent in four years and dropping towards 11 percent at the end. I was wondering if you could address why that's happening.

MR. ADJEMIAN: Yeah. I have the winter reserve margin chart here as well. It was in your package, but, as you mentioned, Michael, the number dips below 15 percent and goes down, long-term, to 11 percent.

I think there's a couple of comments I can make here. Our -- the peak for which we plan our system is the summer peak. That's the peak when our system is stressed the most. Winter is of concern, of course, and we take several steps to make sure that the winter demand is met, and one of those would be, we do not schedule any maintenance during the winter peak period.

Beyond that -- and this was discussed a little bit earlier with Tom Hernandez as to -- and you had mentioned it, Commissioner Deason, about the forced outage rate of units and how -- that is essentially what's shown in the reserves that we're showing here is to capture that.

I'd like to say, from Florida Power & Light's perspective, we have taken significant and -- taken significant efforts to improve the forced outage -- reduce the forced outage rate of our units. In 1987, Florida Power & Light had average system equivalent forced outage rate of about 14 percent. We are -- we have reached now down to about three and a half percent, and we've gotten tremendous avail -- increased availability from our own existing plants, making better use of our plants. So reserve margins that were shown earlier in the slide that was addressed back in 1988-'89, compared back to reserve margins as I'm looking at them today, they're a lot firmer in my view in stand of -- from the standpoint of supply-side, and beyond that, another point Tom had made was the --

COMMISSIONER GARCIA: As a whole you mean they're much firmer, the reserve margin is much firmer today than --

MR. ADJEMIAN: Well, I feel more comfortable that having a -- if you have a forced outage rate that's much lower than it was before, that your reserve margin -- you don't have to maintain as high a reserve margin. Of course, that's what LOLP addresses, so that's why we have that in there, too.

And the other thing is, the mixture of the reserves. If it's all made up of generation, then the forced outage rate is going to take that part down significantly, but if you have supply-side and demand-side resources, then it's -- you're a little better hedged. So that's something else to also consider.

But again, going back to the winter, winter, as I was stating, is not that significant for Florida Power & Light in terms of planning. I also show -- I have a chart here that's not included in your slide, but let me show you -- historically, what I'm showing here is the winter peak versus the summer peak. Summer peak is a solid line that you can see it's on an upward slope, and the winter peak, you can see how erratic it can be. In fact, in the last ten years, summer was our prevailing peak for the entire year. Winter, but for the last two or three years, has been, in that period, of course, lower because of the mild winter.

And another point about that is the duration of when that peak occurs, the winter peak. Those durations are very, very narrow in time. We may have a winter peak that would last perhaps an hour to two hours, which truly can stretch your system some, maybe not a lot, but for one hour to two hours you have a better chance of finding some perhaps purchase, emergency purchase from across our tie lines, as opposed to the summer that you have the peak that persists for maybe six to eight hours, and that available generation may not be there. So we have better ways of addressing those spikes of demand that occur typically for our system in the winter.

MR. HAFF: Now, your plan shows an 11 percent reserve margin in the last two years of the plan, and the four years prior to that 12 percent, and that considers or takes into account load management and your other DSM, correct?

MR. ADJEMIAN: That's correct. That's included in that.

MR. HAFF: Okay. Now -- and your load management can help to reduce those winter peaks which you were talking about a minute ago --

MR. ADJEMIAN: Right, the load management's already factored in as to the firm peak.

MR. HAFF: Well, what happens when you have everybody on load management and they're on for so many minutes pursuant to, I guess, the contract people sign for load management, and then when they all come back on, you turn around and have another brownout because the distribution system is overloaded from everyone turning their heater on at once? I mean, have you done a study of the impact of that? Do you understand what I'm saying?

MR. ADJEMIAN: Yeah, I understand what you're saying. You're saying, if all the load control is released simultaneously, what happens to the T&D system?

MR. HAFF: Or even some of it during a time of peak. I mean, you're at a point where you need load management to keep everyone else's lights on during winter peak.

MR. ADJEMIAN: But, is your concern as to what the effect will be on the T&D system?

MR. HAFF: Yeah, and it kind of goes to the bigger question of why you're not concerned about an 11 percent winter reserve margin on your system.

MR. ADJEMIAN: Well, I was addressing generation reliability. Now, your concern is on the T&D system. Of course, the load management is deployed and operated by the same person that operates the generation system. I mean, they would not release generation -- or I should say -- I'm sorry -- load management and effectively jeopardize the integrity of the grid if -- because they're next to each other, the transmission operator and the generation operator. So I guess what my point is that there's going to be enough coordination that that should not occur.

MR. HAFF: But with an 11 percent winter reserve margin, are -- your reserves look like they're made up mainly from DSM and there's not as much generation driving your reserve, the amount -- your megawatt reserves, and so, thus, you know, you're going to have to implement more DSM during a time of winter peak.

MR. ADJEMIAN: But remember the peak will last, as I was saying, maybe one to two hours, and very quickly you start gradually releasing it, and I don't think it's going to have the effect that, you know, you're anticipating.

COMMISSIONER DEASON: Let me ask a question on your winter reserve margins. Now, I understand that it's a short duration and that you're primarily a summer peaking utility, but have you done a loss of load probability analysis and, if you have, does it meet the requirements for planning purposes in the winter?

MR. ADJEMIAN: Our loss of load probability analysis covers the entire span of the year, and so it considers both winter conditions and summer conditions. So at the end of the year, as you do your simulation of loss of load probability and you look at your cumulative probability of losing load and it says that it's less than .1, then -- or one day in ten years, then that means that factoring in the winter conditions and the winter lack of reserves or access of reserves and the summer conditions, you're still meeting the loss of load probability, that's correct.

COMMISSIONER DEASON: And is that the case for Florida Power & Light?

MR. ADJEMIAN: Yes, it is.

CHAIRMAN JOHNSON: Does staff have any further questions?

MR. HAFF: I just had one more.

We're concerned about the impacts of the Okeelanta/Osceola co-gen facilities, and I guess what we're wondering is, are you going to be able to rely on this capacity as part of your QF purchases? Is it included as QF capacity in your plan or is it not, or how have you addressed that?

MR. ADJEMIAN: Okay. Right now those two

contracts, qualifying facilities total about 120 megawatts. They are in our long-term plan. They're reflected in the ten-year site plan; however, we are in the -- we're in the middle of a litigation with the supplier and at this point, for operational planning, FPL assumes that that generation is not available. If they're there, we'll take the power if we need it, but we assume that they may not be there.

For planning purposes, I am already -- I'm still showing it in the plan because -- well, a couple of reasons. First of all, I don't know how this is going to be resolved in the courts, and, secondly, I don't know that I have to make a decision right now imminently for that particular -- for those particular resources or replacement of those resources. So I don't know if -- hopefully that answer yours question, but they are reflected in the plan right now and I do share some concerns as to how -- what the disposition of those contracts is going is to be.

MR. HAFF: But from a planning perspective for meeting reserves in the out years, you're not at a point yet where that missing capacity has much of an impact?

MR. ADJEMIAN: That's correct.

MR. HAFF: Okay.

CHAIRMAN JOHNSON: Any further questions?

MR. NORIEGA: I had a question.

Yeah, this is Tarik Noriega from PSC staff forecasting section.

In looking at your winter demand forecast for the 1996 and '97 ten-year site plans, I've noticed a megawatt difference of 673 megawatts on the average for the 1997 through 2007 period. What is the main driver of that difference?

MR. ADJEMIAN: Okay. I'm sorry. You're saying you're finding that the winter demand has increased, is that your --

MR. NORIEGA: Your forecast for those ten years have increase for the winter, yes.

MR. ADJEMIAN: Okay. In fact, that's shown in I think it was my second slide that the load forecast had increased and moved the need forward in time.

There were two parts to that increase, but the primary reason is we concluded a survey of housing in our service area and -- I think it was in 1995 -- which showed that one of the key assumptions that goes into development of the forecast is the average size of a home in our service area, and found out that the new homes that are being built are actually a little larger than what we had originally assumed them to be. So I mean, that was part of the -- that was part of the reason that there's been an increase.

MR. NORIEGA: That seems like it's too large a megawatt discrepancy tc be accounted for by housing. Are there any other factors that came into play in that regard?

MR. ADJEMIAN: Yes. Another factor was the actual experience of the peak that we experienced in 1996 in the winter. That tends to be rolled into a -- into part of the formula that develops the forecast. So it does reflect historical experience, and that was another reason why I pushed it up.

MR. NORIEGA: Very well. Thank you.

MR. ADJEMIAN: Sure.

CHAIRMAN JOHNSON: Thank you very much for your presentation.

Florida Power Corp.

MR. RIBB: Good morning. I am Mike Ribb. I am the director of resource planning at Florida Power Corporation, and I want to briefly review some of the highlights of our ten-year site plan. I passed this around earlier, so this should give you a reference point for our slides today.

COMMISSIONER GARCIA: Do you have any extra copies?

MR. RIBB: There were some extra copies put at the end. I don't know if there's any of those left.

CHAIRMAN JOHNSON: Go ahead.

MR. RIBB: Okay. There's been a fair amount of discussion on resource planning criteria. For the planning period of 1996 reported in our '97 plan, we're still using 15 percent of firm peak load for reserve margin reference point and, in addition, checking the loss of load probability for the period. The other thing that we are continuing to look at each year is SO2 emissions and how our system would respond to meeting the emission requirements set forth in the Clean Air Act.

We tend to focus our planning efforts on winter peak demand. As Mr. Adjemian mentioned, these are difficult planning targets because of the volatility of the winter peaks as well as the short duration as well. So balancing the resource formula for winter peaks is quite a challenge.

We've referenced in the dotted line the forecast we had in our '96 site plan, and the solid lines are forecasts for the 1997 plan. What that shows is some contract wholesale sales that we are anticipating those not being renewed on our system. So our wholesale in that later period shrinks down some, and also that does capture, though, the expected retail growth in our area. And this is a -- the former was a capacity view. This an energy view in gigawatt hours. So you see a similar -- you see a similar representation of the total load for our system.

Now, Florida Power has been somewhat active in generation resources. We brought our new Intercession City Siemens unit on line. That was scheduled to come on line in '96, but there were some delays in bringing a high-technology unit on line. So we spent a little more time to ensure that it was as required from our vendor, but that was commercial in January of '97, and has been available serving our system.

We've also, over a several-year period, been looking for opportunities to convert some of our peakers from distillate service to dual-fuel service and provide gas capability for those facilities. In this spring period, we have converted one peaker at Suwannee, which is to the far north -- well, actually not far north from Tallahassee, but far north of where we're headquartered -- a couple of units at our Bartow plant, which is in St. Petersburg, and also I show one unit -- we actually converted two units at De Bary, and with those units running this summer, so far we've captured tremendous fuel savings opportunities for our customers by utilizing dual-fuel capability. So it's been a very -- it's been a real win, I think, for our customers.

Hines Energy Complex, which was called Polk County when it was first under construction, the Hines Energy Complex, the first combined cycle power block is under construction, significant progress. The cooling pond's complete and foundation's in place and equipment being shipped. So we're well under way to meet our in-service date in 1998.

In our ten-year site plan for 1997, we also showed a second unit, a very efficient unit at Hines, the same size power block, coming in November, 2004. That's when the need emerges for that unit.

MR. HAFF: That Intercession City unit, you just get the winter capacity from that unit, right?

MR. RIBB: Right, that's correct. We co-own that with Georgia Power, and they have the dispatch rights to it in the summer, so when we calculate reserve and requirements, all that's taken into account.

MR. HAFF: And in loss of load probability calculations?

MR. RIBB: Yes, sir, that's correct.

MR. BORMAN: If I could ask a question on the -- Todd Borman from commission staff. If I could ask a question about the conversion of the peaking units to dual fuel --

MR. RIBB: Yes.

MR. BORMAN: -- are there any plans to convert any other peakers to dual fuel in the future?

MR. RIBB: That's something that we're looking at. First of all, I guess I'd say we do not have a large gas contract in place at this time. In other words, our system -- we're new to bringing gas onto our system. So we're tending not to assume that we would buy enormous amounts of firm gas to support these conversions.

Each time we look at a conversion like this, we look at the merits of the conversion and anticipate how much gas might be available for it during peaking periods. So what we've probably looked at is a great deal of benefit on the first group of units. We're looking real hard at some potentials for conversions next year as well, but the economics get very tricky, Todd, as you convert more and more units.

MR. BORMAN: The cost-effectiveness of these peaking units that were completed prior to now were based upon using interruptible transportation on the pipeline of about 50 percent, is that correct?

MR. RIBB: I'm sorry. By "50 percent," what are you asking?

MR. BORMAN: 50 percent of the time there would be gas available under an interruptible schedule.

MR. RIBB: It may be difficult to generalize because each the power plant site is characterized differently in terms of what's available. For example, something in St. Petersburg has to deal with the potential congestion in the Tampa-St. Petersburg area for retail gas supply. So its characteristics might be different than one at Intercession City or De Bary. So each one's different, but we assume that, I think -- in simplistic terms, we assume that we could get gas half of the time there might be demand with the unit, and we know we can fall back on distillate if that's necessary. The units are permitted for 100-percent run-time on distillate.

MR. BORMAN: Just one final question. Are there any plans in the works to convert any base load or intermediate load units to get natural gas?

MR. RIBB: Well, after we published the '97 plan, we've been pursuing with FGT an opportunity to convert or to add some gas-firing capability at our Anclote plant. We've been working on trying to accomplish that for many years, and I think we may be optimistically pursuing that at this time, but we did not have a decision like that in time when we published the plan. So hopefully that will add some additional fuel flexibility on our system.

MR. BORMAN: Thank you.

MR. RIBB: Florida Power has 1,048 megawatts of QF capacity on line at this time and there are a few remaining standard offer contracts out that could result in a total capacity of -- a subscription of over 1100. So most of that's built out, on line and operational, as this commission is well aware.

The other thing I wanted to mention is that we did close in July on the buyout of the Tiger Bay facility, which, of course, also is not new information here, and that will be incorporated in our planning criteria as a unit available for service.

A very brief update on DSM goals. We have forecast through 2003 the goals from the Commission Goals Docket. So far in the report submitted in terms of our achievements here, we're ahead of schedule by a year to two years, depending on whether you're looking at summer or winter in terms of megawatts. I also looked in our ten-year site plan when we were discussing this earlier today on the energy portion of the gigawatt hours accomplished, and for 1996, our goal was 78 gigawatt hours, and we had reported achieving 182. So we feel pretty comfortable about the achievements to date on this DSM program, and these are -- goals are incorporated in our planning going forward.

Now, this is a quick look at our capacity resource mix, and this is -- I've got one right behind it on energy, so there is some difference. You see that a large portion of that is coal- and oil-fired capacity. We -- on a capacity basis, we are achieving very significant levels with DSM, qualifying facilities about ten percent. So this gives you an idea of the flexibility of our capacity resource mix at this time.

On an energy basis, I guess the most notable thing here is by the year 2005, we do show some increase in natural gas, and that is the natural gas usage we would expect at some of our peaking facilities as well as the new combined cycles that we're planning.

We've discussed the need for at least the first two units at Hines which are in the planning period, and we have reasonable assurance in our discussions with Florida Gas Transmission that, when the time comes, that that gas should be available for us. We also show the impact of qualifying facilities. Although representing ten percent of our capacity mix, it's generating rcughly 20 percent of our energy mix. So that is a fairly significant impact in terms of our cost to serve.

Okay. Reserve margin review. We've got to look at this from a summer and a winter perspective. We have not included in ours what we would call unspecified capacity purchases, but we do note that in the winter of 2000-2001, we dip slightly below our 15 percent reference point; and I would say, as others have been discussing today, if that -- with that phenomenon not being a sustained annual requirement, we would probably work with the marketplace to try to satisfy that additional need, so that, if we were to show 15 percent, would be less than 200 megawatts that we'd need to pursue in the marketplace. And it shows in the summer fairly substantial available capacity.

And the last item is just a quick review of the Hines Complex, which I think I've covered most of that. I think it's worth noting that we have -- in terms of pursuing that power plant, we have been willing to take some additional risk in trying to find the most efficient equipment that we can on the market. The plant, when it comes in service in '98, will be the most efficient power plant in the southeast, and it's -- and as we did with Siemens, also with Westinghouse on these Hines units, we're willing to take a little bit of additional risk to get those new technologies deployed so we can bring the best and most cost-efficient equipment into service.

That concludes my comments, if there are any questions.

MR. NORIEGA: I just have one question, please. In looking at the 1996 and '97 ten-year site plans, I reviewed the winter demand forecast, and you have forecasted higher up to the winter of 2001. Then there's a drastic drop.

Is there any particular justification for that? That brings your average megawatts down significantly, if we take that ten-year period into consideration.

MR. RIBB: Okay. We're talking about winter peak demand?

MR. NORIEGA: That is correct.

MR. RIBB: Okay. Let me put the picture up.

Okay. You're asking me about this drop here?

MR. NORIEGA: Right. That year, 2001, that particular winter seems to be significant as far as what you've reported in the last two ten-year site plans. I want to know if there is anything that would highlight that --

MR. RIBB: I think the most significant change we're experiencing at that point is with our contract relationships with Seminole. We have some energy sales in the period prior to that and -- which are, in essence, selling them intermediate and peaking power for the three-year period prior to that, and we're anticipating and expect with the -- with their planning to build a unit at Hardee in that time period that, instead of continuing the contract with us, they'll likely pursue other resources. So the bulk of it has to do with the choices that Seminole Electric appears poised to make.

There are some other smaller wholesale contracts that we're currently discussing and are in a period of time where we could be notified of -- that they would go to the marketplace rather than continuing with us. So that is significant, but it has a lot to do with what's happening in the wholesale business at that time, and I think the biggest piece of it is probably recognized in Seminole Electric's plans to start serving that load themselves.

MR. NORIEGA: Very well. Thank you.

CHAIRMAN JOHNSON: Thank you, sir.

MR. RIBB: Thank you.

CHAIRMAN JOHNSON: We will go on to TECO.

MR. WARD: Good afternoon, Commission. My name is Mark Ward. I'm the manager of generation planning at Tampa Electric Company and I will be presenting our ten-year site plan.

The first chart I'd like to show you is our demand and energy comparison from 1996 to 1997. We have a slight increase in our firm peak and summer firm peak -- winter and summer firm peak demands. Our average annual growth rate for 1997 winter firm is about -- to 2005 is about 2.3 percent. Our projected annual growth rate for the summer firm peak is about 2.5, and then we have about a 2. -- a two percent increase in our net energy for load over the planning period.

This is a picture of our existing generating capacity by fuel type. We're almost 90 percent coal. This is snapshot of the past winter. We have roughly 3,653 megawatts installed.

This is generation by fuel type. In 1997, we project a roughly 19,000 gigawatt hours of generation. That grows to 21,000 gigawatt hours in 2006. Again, we're mainly coal-fired generation, but the contribution of the coal-generation reduces by about ten percent over the planning period and that is -- that's picked up pretty much by the use of pet coke.

This is our demand reduction alternatives for the winter. In 1997, we project 1,079 megawatts of demand reduction, and that grows to 1,563 megawatts in the year 2006. Our main contributor is -- to this is conservation, and it grows over the period of time by about six percent. Interruptible decreases as does self co-gen and our load management roughly stays around 25 percent.

This is our demand reduction alternatives for our summer. Again, we begin with 677 megawatts in 1997 and grow to 829 megawatts in 2006. Here the primary contributors are our self-serve co-gen and our interruptible. Interruptible decreases over that period of time by about 12 percent while conservation increases by 12 percent.

This is our reliability criteria for 1997. It's a one percent expected unserved energy and a 15 percent firm winter reserve margin.

MR. HAFF: Now, that's changed since last year, correct?

MR. WARD: Yes, it has.

MR. HAFF: Okay. What was your criteria last year? Wasn't it 20 percent reserve margin and an LOLP of .1?

MR. WARD: That's correct.

MR. HAFF: Okay. We're -- as we heard this morning, we're kind of -- can we infer any relationship between loss of load probablity and this new EUE criteria that you use?

MR. WARD: What expected unserved energy gives us is not only the frequency of loss of load, but also the magnitude, and it gives us an idea, if we lose load, if it's a one megawatt loss or 1,000 megawatt loss. So it provides us with more information for our planning.

MR. HAFF: What kind of study did TECO perform to come up with the revision in your reliability criteria? And we'd like to get a copy of that, if you have one?

MR. WARD: Sure, we can provide you with that. In fact, I think we did provide you with part of it in the FMPA Lakeland hearings.

MR. HAFF: Okay. I don't have it. I'd like to see it.

MR. WARD: I can walk you through briefly what we

--

MR. HAFF: No, I was just curious. You know, I don't know how the impacts of the EUE calculation's done, and we're wondering if you still do LOLP analysis as a side analysis?

MR. WARD: The LOLP that we calculated was an assisted LOLP, and due to the unpredictability of the state situation as it is today, we didn't feel like we could count on this for our planning criteria.

MR. HAFF: Okay. We would just like a copy of any studies that you did to come up with the recommended changes in your reliability criteria and the basis for change.

MR. WARD: Sure, we can provide that.

MR. HAFF: Thanks.

MR. WARD: This is a comparison of our 1996 expansion plan to our 1997. What you'll see first is that we've deferred our next -- our first CT in the future from 2002 to 2003, and a couple of assumptions have changed since last year. We are no longer assuming the Hardee Power Station build-out for the Combined Cycle No. 2.

MR. HAFF: And that's also because of the change in your criteria, right?

MR. WARD: Correct.

MR. HAFF: You're using other criteria this year?

MR. WARD: Correct.

This is our system reliability that we reported in the ten-year site plan for our new expansion plan, and we show EUE and our winter reserve margin. Our summer reserve margin is slightly higher in those years.

This is a look at our integrated resources. The thing that I'll point out here is that our existing capacity decreases by about six percent over the planning period if you include the future capacity additions throughout time, and the demand reduction picks up that six percent.

On an incremental look, we add 783 megawatts during our planning period. Of that, 46 percent is due to generating capacity and 54 percent is due to demand reduction.

This is a slide showing the impact of our demand-side management on the 1997 expansion plan, and the first column shows where our CT -- our first CT would be in place if we held DSM at 1997 levels. Essentially we're deferring the CT for three years.

That's the end of my presentation. Any questions?

CHAIRMAN JOHNSON: Any questions?

Thank you very much.

MR. WARD: Thank you.

CHAIRMAN JOHNSON: Gulf.

MR. MARLER: My name is Mike Marler. I'm with Gulf Power Company. I'm primarily responsible for the production of the customer, energy and peak demand projections and I'll be presenting our forecast for the ten-year site plan, and my colleague, Mr. Pope, will speak to the resource plan.

This is the depiction of our actual 1996 mix of energy sales. We're primarily residential with 43 percent of our sales for the residential class, 29 percent for the commercial class, 18 percent -- almost 19 percent of the industrial class. Street lighting is two tenths of a percent, and it's un-noticeable in the pie chart there. Wholesale, 3.6 percent and losses at 5.4 percent.

Our customer growth expectations historically have been 2.2 percent over the last ten years, compound average annual growth, and our projected growth rate for the next two years is at 1.7 percent.

This is a comparison of our summer peak demand projections. Historically with the impacts of DSM, we have seen a .2 percent compound average annual growth rate, and our projections over the next ten years, with the implementation of our conservation programs, including the new programs for the goals achievement, is 1.3 percent growth. Without the DSM programs, we would have seen 2.6

percent compound average annual growth over the last ten years and 2.0 percent over the next ten years.

Our winter peak demand projections indicate a historical growth of 5.2 percent and expected forecasted at .5 percent, and that's primarily due to the implementation of our residential program, which is a little heavier oriented towards winter demand reduction than summer. Without the DSM, we would have seen 5.2 percent growth historically and we would have expected 1.6 percent growth in the forecast horizon.

COMMISSIONER DEASON: Why do you -- without DSM, why did you expect to see such a reduction from 5.2 to 1.6?

MR. MARLER: I'd like to -- it has to -- go ahead, Bill.

MR. McNULTY: Oh, I'm sorry. I would like to maybe ask a question regarding the customer growth forecast. Actually this kind of gets into, I'm sure, some aspects of your winter peak demand. I notice that the historical population changed in this year's ten-year site plan. I was wondering if you'd give me an indication as to whether that was a census update or why this historical data on total population and historical basis from '86 to '95 changed?

MR. MARLER: The historical data was a census update, and this is a slide of our actual population projection. Historically we've seen 1.8 percent compound average annual growth, and we're projected at 1.6 percent, and there was a historical step change due to the census update.

MR. McNULTY: The total number of customers that has decreased in the 1997 plan over the 1996 plan for the year 2005 is on the order of about 20,000 customers. Is that approximately correct?

MR. MARLER: In the year 2006, our '96 budget forecast had projected 415,000 customers. The '97 update projects 399,000 customers. So it's approximately a 16,000 decrease, and the reason for that revision was primarily due to the retractions in the outcome of the BRAC associated growth that we had anticipated in the '96 budget forecast. The chief of naval aviation training was supposed to relocate to our service area and chose not to.

Additionally, there were two primary fixed-wing squadrons that were suppored to relocate and they also decided not to do that, contrary to what the BRAC recommendations came out to be, and so we slowed down our population growth expectations accordingly.

MR. McNULTY: Do you have any estimates on what those impacts would been for those specific back-outs?

MR. MARLER: I don't off the top of my head. No, I don't, Bill.

MR. McNULTY: Thank you.

COMMISSIONER DEASON: Now, can you answer my question?

MR. MARLER: Yes, sir.

COMMISSIONER DEASON: The question is, why does your winter peak demand forecast without DSM go from a historical of 5.2 to a projection of 1.6?

MR. MARLER: Yes, sir. In the forecast horizon we reflect a greater infiltration of heat pumps. We're seeing, based on our latest saturation data survey, more heat pumps replacing strip heat and room unit air-conditioning and things of that nature in addition to the new customer additions that are required to have heat pumps.

Historically there was not that situation. Electric strip heat was being installed, and with it is incurred a greater winter demand than associated with heat pumps, and the 5.2 percent growth is also abnormal weather growth rate. It's calculated based on the end points, which includes the extreme winter weather that we had in January of '96, and that's primarily the reason for the change in those growth rates.

COMMISSIONER DEASON: So you're saying that the historical had some extreme measurements in it and that the implementation or the saturation of heat pumps into your service territory is the primary drivers?

MR. MARLER: In the forecast, as compared to history, yes, sir.

COMMISSIONER DEASON: When did the -- you said there is now a requirement for heat pumps.

MR. MARLER: It was my understanding that new code does not allow strip heat to be installed in new buildings.

COMMISSIONER DEASON: When was that effective?

MR. MARLER: I believe that was what y'all implemented in 1990, somewhere thereabouts. I don't know specifically.

COMMISSIONER DEASON: So even the historical shows sharp increases in winter peak demand even with that requirement in place during part of that time?

MR. MARLER: Those sharp increases, again, would be due to abnormal weather.

COMMISSIONER DEASON: Thank you.

MR. MARLER: Our net energy for load projections historically have grown at a compound average annual rate of 2.5 percent, and the forecast horizon depicts them growing at 1.9 percent. Without DSM, the growth rate would have been 2.6 percent historically and two percent in the forecast horizon.

And finally this depicts over the planning horizon the change in the mix in energy by class and gives you a feel for the growth rates that we anticipate in each of the classes, residential, commercial and industrial. Wholesale is fairly constant over the period.

MR. POPE: I just have a couple of slides. This is Gulf's existing capacity resources, a pretty heavy mix of coal with some small intermediate gas-fired units, a combustion turbine and a capacity contract with Monsanto Chemicals in Pensacola comprise the 2100-plus megawatts of installed capacity.

Gulf's '97 ten-year site plan is very similar if not almost identical to the plan of 1996 in that Gulf plans to purchase, in the near term, short-term blocks of capacity from others, and our first construction of a combustion turbine -- actually two combustion turbine units is planned for 2003 with a second installation of 2006. And as you'll see on the slide, in the right-hand column is our reserve margins.

I'd like to entertain any questions that you might have.

COMMISSIONER DEASON: The purchases, that's through the Southern System?

MR. POPE: The purchases will be for Gulf Power in order to maintain its reserves. They would come through the Southern Electric System, yes.

MR. HAFF: Does Southern have the available excess capacity to serve your reserve margin deficiencies in the planning horizon?

MR. POPE: That's correct. Gulf is part of the Southern Electric System in that we plan together in concert with the other four operating companies for a target reserve margin of 15 percent on the Southern Electric System. From time to time other utilities will be either long or short, which will make up the 15 percent. So at times we can lean on them when they're long, and if we're long, they can lean on us.

MR. HAFF: Because I'm looking at what you don't have is the winter reserves, and they're below ten percent, or below nine percent every year up until 2003.

MR. POPE: That's for Gulf. The Southern Electric System's reserves are above 15 during the winter time because of the large amounts of gas in Georgia and Alabama.

MR.HAFF: And there is enough excess capacity in Southern Company to serve Gulf's reduction?

MR. POPE: Yes.

MR. HAFF: Okay. All right.

CHAIRMAN JOHNSON: Is that it?

MR. POPE: That's it?

CHAIRMAN JOHNSON: No more questions?

Thank you very much.

MR. POPE: Thank you.

CHAIRMAN JOHNSON: Seminole.

MR. ZIMMERMAN: Good afternoon, Commissioners. I'm Garl Zimmerman. I'm manager of system planning at Seminole Electric Cooperative.

The first chart shows Seminole's history and forecast of energy. We've -- we're forecasting energy of approximately 11,000 gigawatt hours for 1997, growing to 21,000 gigawatt hours over a 20-year horizon. We're showing a -- for the past ten years, we've had an average annual growth rate of around seven percent, projecting about 4.7 percent over the next ten years.

Our winter and summer demand, our historic system peak demand was, in 1996, 3,040 megawatts. We're projecting that to grow to over 5,000 megawatts over the next 20-year period. Demand is projected -- winter demand is projected to grow over the next ten years at about 4.3 percent.

Seminole presently has two different facilities that we own. We have Seminole Plant, which has two 625 megawatt coal-fired units and we own a 14 megawatt share of the Crystal River Unit 3 nuclear unit.

We presently have several purchased power contracts in place, one with TECO Power Services for 295 megawatts from the Hardee Power Station, and that's primarily for backup of our Seminole units. We have 145 megawatts of Big Bend 4 that can be used -- it's a dispatchable resource. It can be used for any purpose. Other contracts with JEA, Orlando Utility Commission and Florida Power Corporation for firm capacity and energy.

In our plans, we have a 440 megawatt gas-fired combined cycle unit. This has been -- the need has been certified by the Commission. It has received Governor and Cabinet approval. All permits are in place and it's scheduled for commercial operation January 1st, 2002.

The conservation and load management programs are primarily the responsibility of Seminole's 11 individual distribution cooperatives, however, Seminole does coordinate the load management program by providing signals -- load signals to the member cooperatives so that the load shedding can be done at the time of Seminole's peak when it's most beneficial and provides the maximum benefit in reducing our overall system peak.

Seminole historically has planned to a one percent expected unserved energy criterion. We also now plan to a 15 percent reserve margin, and the 15 percent reserve margin is the driving criterion. In the past, one percent EUE has -- with the two large coal-fired units has caused us to need considerably more than 15 percent reserves, but as we add more resources and a more diverse mix in the future, the 15 percent reserve margin becomes the driving criterion.

Other future requirements. Seminole issued an RFP last year for 150 megawatts beginning in 2000, 350 megawatts in 2001, and 500 megawatts beginning in 2002. We solicited proposals from other utilities, from IPPs, QFs and marketers. We are currently in the final phase of the big analysis and negotiations and expect to make a decision on the majority of those requirements by the end of this year.

And the last slide I have shows our forecast reserve margin. As I indicated, the one percent EUE criterion caused us in the past to have a fairly high reserve margin. As we get out into the future and add more resources, we're able to target the 15 percent reserve margin and still maintain our one percent or better expected unserved energy.

That concludes my presentation.

CHAIRMAN JOHNSON: Thank you. Any questions?

Thank you very much.

Florida Municipal Power Agency.

MR. CASEY: Good afternoon, Commissioners. I'm Rick Casey with the Florida Municipal Power Agency, and I want to give you a brief overview of our ten-year site plan.

As you'll recall last year -- and this is just a quick history. We currently have 26 member municipal electric utilities in our agency. We were primarily formed back in 1978 to bring two or more electric utilities together to gain economies of scale, primarily in power supply.

We currently have five power supply projects. The St. Lucie project has 15 of our 26 members participating. They represent 75 megawatts of the St. Lucie project, or the St. Lucie plant, Florida Power & Light St. Lucie Plant. The Stanton project has six members which take 64 megawatts from the Stanton 1 -- Orlando Utility Commission Stanton 1 unit. The Tri-City Project has three members that take 23 megawatts from Stanton 1, and the newly operational Stanton 2 project has seven members that take 100 megawatts out of that unit. Our fifth project where we spend most of our time is our All-Requirements Project where we have been serving for several years six cities in the state, all their requirements, and currently we have nine members now signed up and we're growing.

To elaborate a bit, the original six were Ocala, Leesburg, Bushnell, Jacksonville Beach, Green Cove Springs and Clewiston. We now formally have Vero Beach, Starke and Key West either in or about to come into the project, and I'm showing on here the dates that they are beginning to -- will begin to take service from the All-Requirements

Project.

The name of our special project whereby we're bringing in these cities is called the Integrated Dispatch and Operation Project. Originally back in '88 when it was formulated, we were going to bring in the four cities of Vero Beach, Key West, Ft. Pierce and Lake Worth, and as I mentioned a minute ago, two of these have formally decided to come in, and we're currently planning on Ft. Pierce and Lake Worth coming in the winter of '97-'98. That will then give our project a total summer peak of 955 megawatts.

This is a graphical presentation of integrating these four cities into our plans. It's a little bit hard to read on the screen here, but in essence you can see where FMPA has its generation, and bringing in these four cities increases that quite a bit. Then we have our own purchases on top of that, and this is a -- also gives you a feel for what our summer reserve margin looked like for the next ten years.

Very quickly, the significant changes in this year's ten-year site plan compared to last year, our '98 summer peak demand is down by 2.7 percent. '98 net electric load is up one percent, almost one percent, and Stanton Unit 2 is now in service.

This is a comparison of last year's forecast for summer peak demand and the annual net energy for load for the '98 and 2005 time period and the change in growth rates we've used in this year's forecasts compared to last. You can see that the summer peaks for '90 -- let me look here -- I'm sorry -- for '97 are a little bit lower -- excuse me -- '98, I'm sorry -- for '98 are little bit lower and about the same for 2005. NEL is very much the same in '98 and a little bit higher in 2005 in the new ten-year site plan.

Just to quickly review our other aspects of our plan, conservation programs, we have demand-side management programs in place at Ocala and Leesburg. They also have other programs which include residential and commercial and industrial energy audits. In the renewable area, as far as solar technology is concerned, we do participate in the Utility Photovoltaic Group.

Other supply-side alternatives, we are also supporting the development of the fuel cell by participation through APPA in its commercialization, and we still have a commitment to buy one unit once they do go commercial. We do have two cogeneration projects at two of our member cities, Coca-Cola and U.S. Sugar. We have recently undergone our second RFP process, and this past Wednesday was the deadline to receive proposals. We received 22 proposals from 16 bidders for a total of about 3500 megawatts. Our RFP was a combination of long-term needs and short-term needs, totaling 360 megawatts.

We do have flexibility in several of our purchase contracts to take that up or down, and we're trying to be competitive, as everyone else is, and so we've gone to the market to see what's out there in terms of some long-term and some short-term. And so we'll be analyzing those and hope to short-list by October and make the final decision in December.

The long-term option will be compared against our building a unit of our own at Cane Island. That's the bogey for comparison against what others may offer in terms of constructing or selling to us. So that's going to be our primary focus now for quite some time.

Just to mention lastly, we are a member in the Florida Municipal Power Pool along with OUC, Lakeland and Kissimmee. It's been in operation now almost ten years, and it's a share-the-benefits energy pool, and it averages about nine million dollars of savings per year.

And that's all I've got.

CHAIRMAN JOHNSON: Any questions?

MR. FLOYD: This is Roland Floyd with the Commission staff.

How big a fuel cell are you committed to buy, what size or capacity?

MR. CASEY: Well, since it's in the development stage, that's yet to be determined. I think they've been working on -- it's a combination of small cells. I think it's around a megawatt or two. I'm not real sure. And dependent upon how well it produces commercially, they may reduce the size. So it's not a size commitment so mucn as it is, once they decide what's optimal, then it -- it's around one to two megawatts, I believe.

CHAIRMAN JOHNSON: Thank you.

Gainesville.

MR. KAMHOOT: Good afternoon. My name is Todd Kamhoot. This is Mark Spiller distributing copies of Gainesville Regional Utilities' presentation. I'll be discussing GRU's electric system forecast, then Mark will present some demand-side management and generation planning considerations.

The first three pages of your handout are simply some summary overview information on GRU, and the fourth page is a bullet listing of some forecasting assumptions, all of which are included in the ten-year site plan, itself. So I'd like to begin with what is the fifth page of your handout and get right into comparisons of the forecasts.

GRU develops forecast equations for each of its customer classes. Two of the primary drivers in our forecasting models are population, denoted on this graph as P-O-P, and per capita income, denoted at P-C-Y. Both of these variables are provided by the Bureau of Economic and Business Research. This chart shows ten years of history for each variable and the projections used in last year's ten-year site plan forecast versus this year's ten-year site plan forecast.

The chart shows that the new population projections are slightly higher than what were used in last year's forecast. This translates to a hire customer forecast, a greater number of customers in the new forecast. The per capita income projections are a bit more modest in the new forecast than they were projected to be in last year's forecast. This has the impact of lowering average usage in a forecast scenario. The compound average annual growth rates are shown for history and the new forecasts on this chart.

COMMISSIONER DEASON: I would have thought that, with the new contractor, Steve Spurrier, per capita income would be going up in Gainesville?

MR. KAMHOOT: It will be, maybe not as fast as population, though, unfortunately.

This chart shows a comparison of GRU's customer forecasts with ten years of history. The growth rate in the new forecast is just slightly higher, basically projecting customers to grow at about two percent a year. Historically they grew at about three percent a year. The absolute levels are also just slightly higher in the new forecast.

This chart compares our forecasts of net energy for load from last year's plan and this year's plan. Following on the increase in number of customers, sales forecasts have gone up a little bit over last year's. The rate of growth, however, is essentially the same.

Lastly a comparison of summer peak demand forecast for GRU. The new forecast in the year 2006 is one megawatt lower than last year's forecast. You might have expected it to be a little bit higher, given that energy sales went up. We produce our peak demand forecast using a load factor methodology and our assumptions regarding load factors have improved slightly or, in other words, our summer load factor is a little bit better in our new forecast than it was previously so that, therefore, we have essentially the same path for summer peak.

If there are no forecast questions, I'll turn the remainder over to Mark Spiller.

CHAIRMAN JOHNSON: Okay.

MR. SPILLER: My name is Mark Spiller with the Strategic Planning Department of Gainesville Regional Utilities, and the chart that I have here is a representation of the summer demand, which is the peak demand in the GRU system, versus generation capacity, history and forecast out to the end of the 1997 ten-year site plan horizon.

The upper line, the red line represents 115 percent of peak demand that we forecast. The actual peak demand are the bars and the -- I'm sorry -- the red line represents available capacity. The lower line represents the summer peak demand, and the bars represent 115 percent of peak demand. So what you can see --

COMMISSIONER GARCIA: You mumbled that last part and I was having a little bit of a problem understanding the chart.

MR. SPILLER: I'm sorry. Let me start again here.

The red line represents the available generation capacity that GRU has in place. The bars represent 115 percent of the peak demand on our system, history and the forecast, and the green line, the lower line represents the actual summer peak demand per history and our projected summer peak demand.

So what the bars represent effectively is a 15 percent reserve margin, the top of those bars, and you can see that our available capacity will be sufficient to maintain a 15 percent reserve margin throughout the horizon of this ten-year site plan.

Next I'd like to show the impacts of GRU's demand-side management programs within this time period and compare those to the Public Service Commission approved goals which were issued in 1995. As you can see, the estimated savings from the programs that we have in place and are implementing now exceed the Public Service Commission approved goals. We plan to maintain our conservation programs and, in fact, become much more aggressive with our conservation programs through time, and those programs will include our programs to address renewable energy, such as our solar water heating rebate which we have recently put in place, our green pricing program which we have had in place since 1991 and will continue. We finished a project last year, a 10 kW array, and in fact we're looking for our next project to finance under a green pricing scenario.

Also we are starting a green marketing program this year in which we will be marketing photovoltaic arrays for installation on residential rooftops.

Next I'd like to show the energy impacts of our DSM programs and again compare them to the Public Service Commission approved goals. You can see that throughout the planning horizon that the estimated savings from our programs will exceed the Public Service Commission approved goals.

In conclusion, GRU plans to aggressively pursue demand-side management and energy conservation program to promote resource efficiency and to provide our customers to meet their energy end-use needs. Also, GRU does not require additional generation capacity within the planning horizon of this 1997 ten-year site plan.

That's the end of my comments. Are there any questions?

CHAIRMAN JOHNSON: Thank you. Any questions?

Thank you very much for your presentation.

We're going to break for lunch.

(Whereupon, a pause was had in the proceedings.)

CHAIRMAN JOHNSON: We're going to go ahead and finish up. We're not going to take a lunch break. We may be able to finish in the next 15 or 20 minutes. So with that, Jacksonville Electric Authority.

MS. GUYTON-BAKER: Good afternoon. My name is Mary Guyton-Baker and I'm an engineer in the Power Supply Planning and Bulk Power Marketing Department. Randy Boswell is the vice-president of that department and he's passing out handouts.

Today we'd like to give you a brief overview of JEA's ten-year site plan for the years 1997 through 2006. The plan changes to JEA's generating capacity include the restoration of Northside Unit 1's capacity to 262 megawatts. It was earlier de-rated by 11 megawatts. We have 100 megawatts of interruptible load, a purchase of peaking capacity and energy of 40 megawatts in the summer of 1998, 50 megawatts in the summer of 1999, a second purchase capacity of energy that spans over the time frame of October, '96, through to December 2002, and the capacity varies by month and by year but it ranges from 64 to 92 megawatts.

We also have the repowering of Southside Unit 3 to -- as a combined cycle unit by the summer of 2000, and we have -- we included power purchases in 1999 through 2006, and those purchases at the time of this filing were unspecified.

Since that time, we've sent out an invitation for bid and received 11 proposals that included units inside the state as well as purchases outside the state that would satisfy those requirements.

MR. HAFF: I'd like to ask a couple of questions about that. According to what you've been able to find from your ten-year site plan -- I'm looking at winter -- 725 megawatts of your import that you show in here are from unspecified purchases and you're relying on that number to meet your 15 percent reserve margin criteria.

MS. GUYTON-BAKER: At the time of the filing, that included units within our territory or within the state, not just imports from outside of the state. We were in the middle of our integrated resource planning process at that time, and now that we've completed that process, the plan is different. It includes CTs and purchases in the short-term as well as repowering one of our existing units that's in cold reserve, but there's a mix of things now in that plan.

MR. HAFF: And that plan has been finished?

MS. GUYTON-BAKER: Yes, it has.

MR. HAFF: Okay. We'd like, I guess, to get an update of this plan --

MS. GUYTON-BAKER: Okay.

MR. HAFF: -- showing a breakdown of the -- you know, the forms, and also a breakdown of where this import capacity is coming from, because I guess you were here this morning when we had the discussion about the eight percent peninsular. We'd like to see an update of that, if you have it.

MS. GUYTON-BAKER: We can get you that.

MR. HAFF: Thanks.

MS. GUYTON-BAKER: The 1997 plan, like the '96 plan, included the repowering of Southside Unit 3, a three megawatt landfill project, as well as the restoration of Northside Unit 1's capacity to 262 megawatts.

What's different about the '97 plan over the '96 was that we had the category of purchased power versus combustion turbine units.

COMMISSIONER DEASON: The combustion turbine units that the power purchases replace in your plan, were your original plan for you to construct those combustion turbine units yourself or to own those combustion turbines?

MS. GUYTON-BAKER: The '96, plan, was, yes, to own.

COMMISSIONER DEASON: Okay. And now you're looking at power purchases?

MS. GUYTON-BAKER: Uh-huh.

COMMISSIONER DEASON: And you're going to be acquiring through purchases -- are you going to be going through an RFP process --

MS. GUYTON-BAKER: Yes, we've already started that process.

COMMISSIONER DEASON: You feel confident then that it's just going to be more economic to go that route as opposed to acquiring your own combustion turbines?

MS. GUYTON-BAKER: Well, we are and have looked at building them ourselves as well as purchasing from an IPP or other source, and the current plan that we have has a mix of both.

COMMISSIONER DEASON: Okay. Thank you.

MS. GUYTON-BAKER: The demand and energy forecasts for the 1997 ten-year site plan shows an increased annual growth rate in the summer and winter peaks as well as the net energy for load. The forecast is based on a trend analysis of historical data, and to benchmark the short-term forecast, JEA staff looked -- or interviewed local experts on JEA's economy and found that that was -- that the projections that we've made are good projections. JEA also in prior years have tended to not think that the strong growth that we had in the past would continue into the future, and our philosophy has changed along that line.

Lastly, this is a graph of JEA's winter peak demand versus available capacity. The bars show existing capacity plus capacity additions and changes over the ten-year time frame. The bottom line shows JEA's winter peak demand, projected winter peak demand, and the top line shows the 15 percent reserve above the peak demand, and in our plan you can see that the capacity at minimum meets the 15 percent reserve margin.

And that concludes my forecasts -- I mean, excuse me -- my presentation. Any questions?

MR. HAFF: Yes. Are you familiar with the Commission staff's supplemental data request that we sent in February?

MS. GUYTON-BAKER: No, I am not.

MR. HAFF: Okay. We asked all the utilities to provide us some supplemental information on their plans to try to help us try to assess the --

MS. GUYTON-BAKER: Yes, I'm aware of that.

MR. HAFF: -- you know, the inner workings behind the summary or the plan that you filed.

We've asked for it by letter and talked two or three times and have gotten nothing from JEA. Do you plan on responding at all to that request?

MS. GUYTON-BAKER: I had not received your request.

MR. HAFF: Okay. It was sent to I guess it was the director of your planning division in February.

MS. GUYTON-BAKER: Okay. Are you speaking of the packet that shows the large volume of --

MR. HAFF: Fuel forecasts, sensitivities to load forecasts.

MS. GUYTON-BAKER: Okay.

MR. HAFF: We haven't received anything, and I've talked to somebody over there a couple of times and they've mentioned -- they've promised me three times that I'll get something and I've not seen it yet.

MS. GUYTON-BAKER: Okay. I wasn't aware of your phone calls.

COMMISSIONER DEASON: Any further questions?

I think not. Okay. Thank you for your presentation.

City of Lakeland.

MR. ELWING: Good afternoon, Commissioners. Thank you for your time. My name is Paul Elwing and I'm here representing the City of Lakeland. I'll wait just a moment as the packets finish getting passed out.

The first graph I'd like to put up this afternoon is just a comparison of our customer forecasts over the past two years. Lakeland is continuing to experience growth. We are in a high growth area between Tampa and Orlando, and so our forecast for this year is showing continued growth. The '96 forecast, our growth rate for customers was about 1.98 percent. This year we're forecasting about 2.08 percent over the ten-year horizon. We're predominantly residential. About 81 percent of our customers are residential in nature.

Net energy for load, we're forecasting a slightly lower net energy for load growth and ultimate forecast for this year. Our '96 forecast, we're forecasting a rate of about 2.8 percent. This year about 2.78 percent with also a slightly lower starting point. So we're seeing slightly more moderate energy growth, and again, energy contribution on our system is heavily residential at about 52 percent and about 25 percent commercial, and the other 20 percent is industrial and municipal, city use.

COMMISSIONER GARCIA: Could you explain that graph a little bit? I want to make sure that I understand it. The higher bar is your historic and the lower is your forecast?

MR. ELWING: That is correct. The '96 forecast is the higher set of bars in the background. As I said, our forecasters last year were forecasting both a higher starting point for energy consumption as well as a higher growth rate, which ultimately led to a higher -- total higher energy forecast. This year they are forecasting a more moderate growth rate and a more moderate starting point.

Going on to winter peak demand, we are forecasting a slightly higher winter peak demand over the next ten years as compared to the '96 forecast, with growth rate also being slightly higher. We are, as I said, very highly residential and the residential customers tend to drive our winter peak. Our winter peak is also our seasonal peak. And so we tend not to see much saturation as far as winter demand.

We frequently see, when customers -- or when we have a cold snap come through, customers can very easily go down to the local K-Mart or Wal-Mart and buy strip heat in the form of portable heaters and plug them in, and so our residential customers do drive our winter demand.

Summer peak demand, we're forecasting a lower summer peak demand over the next ten years. Conversely to the winter peak demand, we are seeing saturation on our system, again being predominantly residential. We're getting more and more heat pumps on the system and also air-conditioning is not a commodity that is readily bought at the local hardware store or a Wal-Mart or K-Mart. So we do see a certain amount of saturation in our summer growth.

Our summer growth rate from last year was approximately 2.9 -- 2.09, percent this year 2.03 percent.

Moving on to fuel forecasts, we're not -- our fuel forecasters and fuel supply people are not forseeing any radical changes in fuel prices over the next ten years, and so we see a relatively constant relationship between the fuels over the next ten years. Coal and gas are Lakeland's main fuels, and we're expecting -- as I said, expecting a moderate to stable growth rate in prices over the next ten years.

Lakeland is currently burning petroleum coke and RDF in our coal unit. Currently Lakeland's coal is made up of approximately 70 percent long-term fixed price contracts, about 30 percent are spot price contracts. Gas for Lakeland is approximately 30 percent long-term and 70 percent spot. Our ultimate goal for gas in Lakeland is a about a 50/50 mix of fixed contracts and spot purchases.

Based on our current filed plan, just to give you an idea of our capacity mix that we're expecting, currently for 1997, you can see our utility on a capacity basis is heavily weighted on gas. About 60 percent of our capaci.y is gas, about 27 percent coal, two percent RDF, seven percent in demand-side management programs, and about four percent purchases.

The plan as proposed in the April 1 filing, we're proposing adding additional coal capacity which would add to our fuel diversity and brings that up to almost 40 percent, with gas remaining at around 51 percent and the other continuing with RDF. Demand-side management increasing as well, purchases decreasing.

To give you a little bit of information about our conservation efforts, Lakeland is very much pro conservation. Our residential demand-side management has been very successful for us. We call it our SMART program, Saving Money and Resources Together. It's a direct load control of water heat and HVAC systems. As of January 1, 1997, we had 26,611 participants, which is roughly 30 percent of our residential customers participating in the program.

Our other large residential program is a loan program whereby we, in cooperation with one of the local banks, provide low interest loans for thermal efficiencies and upgrades in the home, such as heat pumps, insulation, caulking, et cetera.

Lakeland also has some commercial programs. They have not been as successful as residential programs, but we are still out there trying to market those. We have a few commercial lighting customers. We have one thermal energy storage customer and then we do have our high pressure sodium outdoor lighting program which has been successful in converting all of our public street lighting, as well as being offered to customers for security lighting, private area type lighting.

Winter demand reduction, as I said, Lakeland's been very aggressive in demand-side activities, and our winter demand reduction reflects that we currently have about 49 megawatts of controlable load, which equates to just under two kW per customer, and we're forecasting this to grow to about 88 megawatts by 2006. So we're continuing to pursue demand-side management.

Summer demand reduction, we're trying to stay aggressive in that as well. Because of the nature of the devices being controlled, hot water heating and air-conditioning systems, we don't get as much reduction in summer as we do in winter. It's currently about 20 megawatts of reduction, which is equivalent to about just under 1 kW per customer, and we're expecting that to grow to about 39 megawatts by the year 2006.

Another area that Lakeland is getting very active in is in the area of renewables, and we have number of programs going right now and a number of potential programs that we're trying to get off the ground. One program that we've got going right now is our solar street lighting program, which is about three years old, and we have 20 solar powered streetlights in place. They replace a typical 70 watt fixture, and those panels have -- or those lights have a battery backup system that provides those lights with up to five nights' worth of service in case of cloudy weather.

There's a picture on the next page in your packet. I'm not going to put it up for here for time's sake.

One of the other programs that we are pursuing is a distributed generation via solar thermal collectors. What this is a solar hot water heater program, and this would provide the customer with hot water while also reducing demand on the utility grid. The concept in this program is for Lakeland to own, operate and maintain the units thereby removing the obstacle of capital investment by the customer, hopefully increasing penetration.

The research and development is funded by the Florida Energy Office and is administered by the Florida

Solar Energy Center. The preliminary analysis has been completed and we have the first unit in service in the field right now. The next phases will be to install approximately 50 more units on Lakeland's system for a two-year pilot project, and then hopefully be able to go commercial with this.

These systems, based on our analysis, are providing us with a two to four kW demand reduction on each system. So we're -- hopefully they'll be very cost effective for us as a demand-side alternative.

The other two projects that are listed up there are PV type systems for residential applications. The one is -- the first one there is an effort to test the integration of a PV system into the utility grid as well as to test the survivability in a high lightning area. One of the unique things about a PV system is that, if you have a downed conductor somewhere and the sun comes back out, in effect, that PV system can feed power back into that conductor, which presents a safety hazard to the linemen who are repairing power lines after a storm.

Part of the project will be to test and develop an interface that would disconnect that system if there is a downed power line in the area.

The last program listed up there, the name sounds very similar, but this is a program that would be comparing two homes, one equipped with a photovoltaic system and high efficiency appliances with a standard spec-built house to further prove the efficiencies and energy savings that PV can bring to the customer and to the utility.

Going on to page 14 of your packet today, just a brief description of our resource planning process. Lakeland uses a 15 percent reserve margin at time of annual peak to plan its system. As I mentioned earlier, our annual peak is winter, so that's -- so we plan for a 15 percent reserve margin at winter peak, and we also use an integrated resource planning process that integrates the supply and the demand. The current map that's in the ten-year site plan as filed looked at approximately 20 different build options, over 30 different purchase options through an RFP process which is still ongoing. We have not closed that out or made the decision yet, and over 60 BSM options were looked at.

We issued an RFP early this spring, just prior to submitting the ten-year site plan, and so there were not a lot of details in the plan concerning the RFP, but just to bring you up to speed a little bit, we had 14 respondents with over 30 different options. Four of those were utilities and the remainder were IPPs and marketers. Options offered ranged from EPC turn-key type options to unit power sale as well as market power options.

All told, there were over 10,000 megawatts of power offered to us. We currently have that short-listed down to four and we're in the process of entering discussions with our number-one respondent to get a better understanding of what they responded within the RFP so that we can then compare that against our best build alternative to have the best possible comparison.

How Lakeland plans on meeting future needs: Over the short term, five years or less, we plan on meeting our future needs with existing capacity, demand-side management, firm purchase contracts and/or other peaking resource opportunities. Our long-term needs, five years and beyond: An economic base mix of existing capacity, demand-side management, purchases and build options.

What our plan as filed currently is showing: Proposed capacity additions in 2001. We're still shooting for the project that we brought to this commission for information purposes this time last year and which was a DOE clean coal technology project. The first phase would be 157 megawatts of coal-fired capacity in a pressurized circulating fluidized bed unit. The plan indicates that in 2002 we would need some peaking power, 56 megawatts of combustion turbines to meet reserve margin requirements. 2003, the DOE project get a modification. That's part of the overall project. An additional 12 megawatts would be added via topping cycle technology, and then in 2005, another combustion turbine for peaking purposes to meet reserve margin.

Another way to show that on the next page, our future resource needs: To kind of give you a comparison, the first column on the left there is our cumulative new load that we're projecting over the next ten years, and this is without reserve. In other words, we're not adding anything in to meet our reserve margin requirements. We're forecasting approximately 190 megawatts of new winter load over the next ten years. Combined with that about 39 megawatts of new additional DSM unit additions are on there as per the last sheet.

We also are planning retirement of two units when that coal unit goes into service. That reflects Larsen Unit 6 and 7, which are 38 and 31 years old respectively now. And then we currently have some purchase contracts which are shown out on the far right-hand side.

Lakeland is also looking at the possibility of additional retirements on its system of aging units. We currently have about 139 megawatts of additional capacity that will be 30 years old or older by the time the proposed unit addition goes in, and so it may be cost effective to replace that capacity at some point in the future as well.

Graphically what does that look like? Our winter capacity and resources, the lower tier of blocks there is capacity, starting out with existing capacity and stepping up as we add capacity based on the plan. Firm contracted purchases are the hashed marks on your black and white handout copies, and then the -- for three years there until the unit goes in place, we're projecting some short-term other purchases to meet reserve margin requirements just over the winter peak.

COMMISSIONER GARCIA: Do you miss it in -- is it 2003?

MR. ELWING: In 2003, no, sir; we're right on the line. It's a little hard to tell graphically from the handout, but if memory serve me right and the numbers were run correctly, we maintain 15 percent reserve margin across each winter peak throughout the plan.

COMMISSIONER DEASON: What are your other purchase options that allow you to meet the criteria in the years '98 through 2000?

MR. ELWING: Our business development group back in Lakeland is in charge of short-term purchases and market opportunities, and they have indicated that they would go to the market to purchase additional capacity just over the winter peak. They have been watching the market closely and feel that there is sufficient short-term capacity available just over winter peak in these interim years, that we -- again, that's just a very short-term, and those amount to on the order of 20 to 40 additional megawatts over the next couple of years. So it's not a lot.

COMMISSIONER GARCIA: But you're not engaged in those contracts right now. Those aren't existing relationships. These are things you hope to develop or --

MR. ELWING: That is correct. They have not been secured.

COMMISSIONER GARCIA: So this isn't firm. This is -- you're hoping to be able to pick up on the market?

MR. ELWING: That is correct. We do have one firm contract that does have a supplemental clause, and so we may try and exercise that first.

COMMISSIONER GARCIA: Because it's a considerable amount, and in other proceedings that have come before us, one of the issues has been the lack of availability of some of these contracts into the future.

MR. ELWING: We would certainly agree with you over the long term, and that's why we're only showing it in the next two to three years. Again, our marketing people feel confident that there is some incremental capacity out there for short periods of time, and we feel that that would coincide with our need.

And my last slide is from a summer capacity perspective. Being a winter-peaking utility, if we meet winter peak, we're certainly covered for the summer. So, as you can see, the reliability targets shown on there, which is a little hard to see on the overhead today -- but the reliability target that's listed on both of these is our peak load plus our 15 percent reserve margin. So we feel we've got summer more than adequately covered.

That concludes my presentation today. If there are any questions, I'll be happy to answer them.

COMMISSIONER DEASON: Questions.

I don't think there are any. Thank you.

MR. ELWING: Thank you.

COMMISSIONER DEASON: City of Tallahassee.

MR. BYRNE: Hello, my name is David Byrne. I'm chief planning engineer for the City of Tallahassee. This is my presentation on our 1997 ten-year site plan.

Some statistics on Tallahassee's electric system. We have approximately 88,000 customers and we serve an area of about 221 square miles. Currently we own and operate about 500 megawatts of generation resources and we retain firm power contracts for about 100 megawatts.

Our all-time high peak demand was 533 megawatts, and that was achieved in February of 1996. Tallahassee computes its system resource needs based on our summer peak loads. Our load forecast is a 20-year forecast, and based on that forecast, we intend to meet a 17 percent reserve margin level. That's our -- that's the reliability target that we have chosen, and the summer demand growth in the 1997 forecast is about 1.88 percent annually, which is a little bit higher than we projected in the previous plan, but not significantly, and as a result of that load growth and also the loss of or, rather, the termination of one of our purchase power contracts for 35 megawatts, we're projecting a shortfall in capacity starting in the year 2000. As you can see on the chart, it starts at about a need for 102 megawatts and grows as we move out through the ten-year site plan study period. This chart doesn't include any of the new additions that we have planned.

COMMISSIONER GARCIA: When are those new additions slated to come on line?

MR. BYRNE: What we're -- what I'm going to get to is our plan for meeting some of those shortfalls, and I'll be on that in the next slide.

COMMISSIONER GARCIA: Okay.

MR. BYRNE: This chart gives a picture of our resource and demand comparison. The bottom portion of the area graph shows our existing generation, about 500 megawatts right now. We have some purchased power stacked on top of that, and you can see that in 2000 there's a drop in the level of purchases that we have. We have a currently UPS contract with the Southern Company for 75 megawatts and that will be terminated in May of 2000. The bold bar across the top represents our projected peak load in the summer, plus 17 percent reserve margin, and you can see that we're meeting that through 1999, but at the tim. that we lose the capacity purchase contract, we'll be in a shortfall situation.

The way we plan to meet the projected shortfall is one that was based on the results of the need study that was approved this spring by the PSC. Part of our resource plan will include conservation and energy efficiency programs, or demand-side management, and another part of it, a much larger portion of meeting the shortfall will be to build Purdom Unit 8, which is a 250 megawatt gas combined cycle plant. We also looked at short-term and long-term purchased power options but found that they were not economic.

The City's demand-side management includes a mix of residential and commercial programs. During the need study that we conducted over the last year, we found that, although we're pursuing demand-side management goals which meet the filing we made with the PSC in 1996, those DSM contributions are not going to be sufficient to either avoid or defer our next supply-side resource. We are continuing, however, to look at increased enhancements in our DSM program.

Our supply resource, as I stated, was Purdom Unit 8. The unit's to be added at the existing site in St. Marks, Florida, by May of 2000. It will be a 250 megawatt gas combined cycle plant with a high efficiency of about 7,000 Btus per kilowatt hour. We expect the capital cost to be about $110,000,000 or $440 per kilowatt, and no new transmission facilities will be required for this facility.

For the Purdom project, there are a few milestones. The first one we've passed at this point is the need determination. As I said, this was certified this June by the PSC, and upcoming is the permitting for the project, and expected completion date is in the spring or summer of next year, 1998.

In addition to going forward on permitting the project, we're also planning on retesting the purchased power market prior to making the final decision to build the project. We just want to make -- have final certainty at least at the farthest out date in the future as possible that we are making the right economic decision.

That concludes my presentation on the resource additions.

We also have some transmission plans. I did say that the Purdom project itself would not require any new transmission lines. It will, however, require a couple of upgrades of some of the lines. We plan to re-conductor two lines so that the additional power from the Purdom 8 project can be delivered to our system.

Additionally, we're also building some new substations to serve growing load on the east side of Tallahassee and will be connecting those to our existing system with some new 115 kV transmission lines. We'll be expanding our network with two new loops on the east side, and those will be primarily to serve new load, not to add to the state transmission network.

And that concludes my presentation.

Are there any questions?

COMMISSIONER DEASON: Questions?

I think there are none.

Thank you for your presentation.

MR. BYRNE: Thank you.

COMMISSIONER DEASON: Staff?

MS. PAUGH: Mike Haff is handing out supplemental question to which staff has requested responses. We will follow up with a memorandum to all of the participants in these proceedings insofar as some of them have already departed. We'll make copies available at either side of the room for your pick-up on the way out.

CHAIRMAN JOHNSON: Any other concluding comments?

MR. JENKINS: The only thing I'd like to add is, the thrust of these questions were put together because of staff's uncertainty of whether an independent power producer can be certified under our present power plant siting act. We think the issue becomes important not only because of where the rest of the nation seems to be going but because of what we appear to see as the capacity shortfalls in the later years.

We do not want to restrict or harm Florida's economic growth or electric reliability by restricting people who want to build new power plants from building because of our laws or our interpretations of laws. We are asking for interested persons to provide us a reply to those questions within a month.

Do you want to give them a date certain?

MS. PAUGH: September 9th.

COMMISSIONER DEASON: Answers are sought by September the 9th.

MS. PAUGH: That's correct.

MR. JENKINS: And if you have any questions about the questions, do not hesitate to give -- you, Leslie?

MS. PAUGH: Please feel free to contact Michael Haff or myself, Leslie Paugh, with PSC staff.

COMMISSIONER DEASON: Okay. Anything further?

MR. JENKINS: That's it.

COMMISSIONER DEASON: Hearing none, I want to thank everyone for your participation and your presentations at today's workshop.

This workshop is now concluded.

(Whereupon, the proceeding was concluded at 1:50 p.m.)

CERTIFICATE

STATE OF FLORIDA)
COUNTY OF LEON)

I, RAY D. CONVERY, Court Reporter at Tallahassee, Florida, do hereby certify as follows:

THAT I correctly reported in shorthand the foregoing proceedings at the time and place stated in the caption hereof;

THAT I later reduced the shorthand notes to typewriting, or under my supervision, and that the foregoing pages 3 through 149 represent a true, correct, and complete transcript of said proceedings;

And I further certify that I am not of kin or counsel to the parties in the case; am not in the regular employ of counsel for any of said parties; nor am I in anywise interested in the result of said case.

Dated this 18th day of August, 1997.

Ray D. Convery

RAY D. CONVERY
Court Reporter