BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. UNDOCKETED

In the Matter of

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

BEFORE: CHAIRMAN LILA A. JABER
COMMISSIONER J. TERRY DEASON
COMMISSIONER BRAULIO L. BAEZ
COMMISSIONER MICHAEL A. PALECKI
COMMISSIONER RUDOLPH "RUDY" BRADLEY

DATE: Friday, August 16, 2002

TIME: Commenced at 9:30 a.m.
Concluded at 12:27 p.m.

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

REPORTED BY: JANE FAUROT, RPR
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IN ATTENDANCE:

WM. COCHRAN KEATING, FPSC Office of General Counsel.

MICHAEL HAFF, FPSC Division of Safety and Electric Reliability.

MARIO VILLAR, LINDA CAMPBELL and LEO GREEN, representing Florida Reliability Coordinating Council.

MARIO VILLAR, representing Florida Power & Light Company.

BEN CRISP, representing Florida Power Corporation.

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

JOHN CURRIER, representing Tampa Electric Company.

RICK CASEY, representing Florida Municipal Power Agency.

TODD KAMHOOT, representing Gainesville Regional Utilities.

MARY G. BAKER, representing Jacksonville Electric Authority.

ROBERT MILLER, representing Kissimmee Utility Authority.

PAUL CLARK, representing the City of Tallahassee.

MYRON ROLLINS, representing Orlando Utilities Commission.

IN ATTENDANCE: (Continued)

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

P R O C E E D I N G S

CHAIRMAN JABER: Let's go on the record. Counsel, read the notice.

MR. KEATING: Pursuant to notice issued July 18th, 2002, this time and place have been set for a Commission workshop in the undocketed matter in re, review of ten-year site plans of electric utilities.

CHAIRMAN JABER: Okay. Mr. Keating, I note that we have got the first presentation by the Florida Reliability Coordinating Council. We have a set amount of time for each of the industry representatives to speak to.

Mr. Haff, I intended to just turn it over to you all at this point and you can call the presenters up in the order that you have all agreed upon.

MR. HAFF: Okay. I'm Michael Haff from the Public Service Commission staff. I would like to let you all know that we have a slide projector over here that you can use for your presentations, and there is also a connection for anyone with a slide show on their computer so we can use that, as well. We will go in the order of the FRCC, then the investor-owned utilities and the munis and Seminole, and we will have a little time at the end if there are any public presentations or comments. And as the Chairman said, we will try to finish by 1:30. I guess we will go on and let the FRCC begin. And I will just mention that anyone that is presenting today to state their name and if there is any handouts to give them to our court reporter to help in doing the transcription. Thanks.

MR. VILLAR: Good morning, Commissioners. My name is Mario Villar. I'm manager of resource planning for Florida Power and Light Company, and I am appearing today on behalf of the Florida Reliability Coordinating Council. I am a member of the resource working group of FRCC that looks at the load and resource plan for the state and the reliability assessments. My presentation today will consist of a review of the FRCC's load and resource plan for 2002, and also a brief description of the reliability assessment work that was done at the resource working group.

The graph that is up on the screen right now, it's a little hard to see because of the glare, but it shows a firm peak demand for both summer and winter for the planning period from 2002 to 2012. And it shows an average growth rate for the summer peak demand of 2.44 percent and a 2.37 percent average growth rate for the winter demand.

The next graph shows the capacity additions in the state for the planning period. This one only shows utility installed capacity additions. We don't have a graph that includes any power purchases that are being made. And this shows about 17,000 megawatts of additions being made over the ten-year period.

The total available capacity in the state. You can see here the changes from 2002 to 2011. We have roughly 44,000 megawatts of capacity, split into the various components, gas, oil, nuclear as shown on the pie chart here. And that number growing to approximately 57,000 megawatts in 2011. You can see there is a significant increase in the gas mix.

COMMISSIONER DEASON: Let me ask you a question about the oil. I see that it is slightly going down from 21 percent to 20 percent, but the 20 percent of a much larger pie shows an actual increase in the absolute amount of oil generation. Is that true?

MR. VILLAR: This graph only shows a capacity mix, Commissioner. You will see the next one shows the actual generation mix in terms of gigawatt hours. This is the number of megawatts, if you will, that are available in the state. The next one shows the actual consumption.

COMMISSIONER DEASON: Right. And I understand that this is capacity, but is there going to be an absolute increase in the amount of oil capacity in the state?

MR. VILLAR: As far as I know there is no absolute increase in the amount of oil capacity. There may be some units that have dual capability, but I really haven't looked at that one specifically.

COMMISSIONER DEASON: All right. Thank you.

COMMISSIONER PALECKI: Is there a decrease in nuclear?

MR. VILLAR: No, there is no decrease, it's just you have a much larger pot of megawatts. And nuclear hasn't changed, that is the reason why the number goes down.

COMMISSIONER PALECKI: Thank you.

COMMISSIONER BRADLEY: Excuse me, what does NUG represent?

MR. VILLAR: NUG. NUGs, nonutility generation. Commissioner Deason, this is the one that shows the actual fuel mix change from 2002 to 2011, and you will see there that oil does drop from 9 percent of the consumption in 2002 to 5 percent of consumption in 2011.

COMMISSIONER PALECKI: Why is there a reduction in nonutility generation?

MR. VILLAR: This only reflects the actual contracts that are currently in place with the utilities, and there is a number of qualifying facility contracts that are expiring in this time frame, so I would assume that there would be a reduction as a result of that. It doesn't necessarily mean that that will be actually the case as they come about. Those contracts will be renewed or they could be sold on an as-available basis. This only reflects what is under firm contract to utilities at this point.

COMMISSIONER PALECKI: Thank you.

MR. VILLAR: The next bar graph just shows the amount of DSM load management and interruptible resources that are available to the state. And you can see it is holding at a fairly constant level. I think at one point the Commission was concerned as to whether or not we had additional generating resources instead of just depending so much on DSM. And the fact that the DSM is not increasing here shows two things. One, the cost-effectiveness of DSM has changed over the years, and also we are adding some additional generation. So we are going to have some hard resources as opposed to relying so much on DSM.

COMMISSIONER BRADLEY: On this graph what does other represent, what are some examples of other?

MR. VILLAR: I'm sorry, Commissioner, what is the question?

COMMISSIONER BRADLEY: Other. You have other, NUG, other next to NUG on both of them.

MR. VILLAR: You are going back to the prior bar graph?

COMMISSIONER BRADLEY: No, I'm on the same graph.

MR. VILLAR: The fuel mix graph?

COMMISSIONER BRADLEY: Yes. I'm just trying to get some idea as to --

MR. VILLAR: I probably would have to go back to the actual load and resource plan, but I believe in the other what we have included in there is some interchange contracts that are in there.

MS. CAMPBELL: There may be interchange and there is in the IE411 data and the ten-year site plan data there is just other types of fuel sources. They may be small diesels and things of that nature that aren't necessarily reflected in some of these others, so that is also what is included there.

COMMISSIONER BRADLEY: Okay.

MR. VILLAR: This graph is a summary of the reserve margins for the state from 2002 to 2011 for both summer and winter, and highlighted in there is the FRCC minimum reserve margin standard for the region of 15 percent. You will see from the graph that reserve margins are projected to be above the 20 percent level for the whole period from 2002 to 2011, way above the FRCC minimum reserve standard.

I want to move on a little bit to what was done at the FRCC in terms of the reliability assessment. We took the data that is submitted by the utilities in response to the load and resource plan information that you just saw and we conduct a review of the following categories in this year. We looked at reserve margins, we did an analysis of the availability and the forced outage rate of the units. We looked at load forecasts and we also obtained information from the gas pipelines that are serving the state at this point.

The purpose of the reserve margin review is to ensure that the regional planning reserve margin meets the minimum 15 percent FRCC standard. And from the graph, the bar graph that I showed you a couple of minutes ago it does meet it throughout the whole period.

Generally, the FRCC has looked at not only reserve margins, but also loss of load probability. And because a loss of load probability analysis is one that is very time-consuming, and since we had high reserve margins and loss of load probability results in prior years have been extremely good, instead of conducting a loss of load probability analysis we looked at a proxy for loss of load probability, and to see whether there was any need to actually conduct an analysis. What we did there is to see whether there was any deterioration in the forced outage rate of the units in the state, or whether the forced outage rates that were projected were expected to either get better or stay at a fairly consistent level.

If that is the case, then there is no need to conduct an actual loss of load probability analysis, because we are basically adding a lot more units in the state which increases reliability and the units are performing as well as they have in the past. So rather than conducting that complete analysis, we did a comparison of forced outage rate trends for various years. And while availability of units is not used in loss probability analysis, we also looked at the availability of units as another indication as to whether or not we needed to be conducting a loss of load probability analysis.

The graph here is very hard to read on the screen up there, but it basically shows the comparisons of the forced outage rates for the region and for various projections. Let me see if I can point out the latest one. The one with the black squares is the 2001 latest set of figures and you can see the numbers there are decreasing in the projected time frame. And they are lower than or holding constant to the ones that have been projected before. So on the basis of that analysis, we concluded forced outage rates are not getting worse, they are holding or getting better. We don't see any reason to conduct a loss of load probability analysis.

This one is also very busy. It compares the availabilities of generating units on a megawatt weighted basis for the region for various years projections. And again it shows similar trends to the forced outage rate analysis. The 2001 latest numbers are also shown as the black squares towards the top of the curve there. So the availability of units continues to stay at a fairly high level. Again, giving an indication that there is no need to conduct a full blown loss of load probability analysis.

I think last year the FRCC presented to the Commission the results of a thorough analysis of the load forecasting methodologies for the utilities, et cetera. Doctor Green, I think presented that. Since the methodologies that are being used by the various companies to arrive at their load forecasts have not changed over the current year, planning year, we didn't see a need to conduct any additional analysis other than verify that the forecasts were still on track. And for that we looked at a couple of measures, whether or not there were deviations between actual and forecasts in terms of are you consistently over or underforecasting your load and whether or not the loads were -- or the forecasts were diverging. In other words, your actual loads were separating from your forecasted ones. And on the basis of those analyses, we see no trend in either over or underforecasting. And actually divergence from actual to forecast has been decreasing over time. So we feel confident of the load forecast on that basis.

We also looked at the availability of gas in the state transportation and the pipeline expansions that are attendant to that. We received information from both FGT and Gulfstream, the two pipelines that are currently serving the state, and FGT is currently completing work on Phase 5 and Phase 6 expansion projects. I think when Phase 6 expansion is completed at the end of 2003, somewhere in that time frame, they will have over 2.2 billion cubic feet per day of capacity available in the state, subject to check. That is just a number from my recollection.

The FGT pipeline has access to supply areas that are from Texas to Alabama, the Gulf of Mexico, and it also has -- I think one of the benefits that is significant, now that we have another pipeline in the state, is that we also have interconnection capability between the two pipelines. From a reliability perspective, the FGT pipeline has multiple compressors at the various stations so that if one fails you can still serve the needs of the state and availability of gas from various supply areas into Florida.

The most recent addition to the transportation capability and the gas supply in the state is from the Gulfstream natural gas pipeline, which was placed into service around Memorial Day of this year, and it has the capacity of over a billion cubic feet per day. Like I said, there is two interties that are either planned -- I don't know, they are actually in operation now with FGT providing the ability to move gas back and forth between the two pipelines.

Again, this slide just covers mostly the supply scenario for Gulfstream, the number of reserves that are available, et cetera. And the Gulfstream pipeline has the ability to expand similar to FGT.

To summarize, the reserve margins, the planning reserve margins for the state remain at or above the 20 percent level for the ten-year forecast period, and the FRCC minimum reserve margin standard is 15 percent. The forced outage rates continue to be extremely low, similar to the ones that we saw in 2001. The availability of generating units in the state continues to be very high. The accuracy of the load forecast has remained high, and we have more pipeline capacity now than we have had in the past. So we expect the availability and the transportation to be adequate to meet the needs of the state.

In summary, we expect the reliability of the state to be adequate from a planning perspective. That concludes the presentation.

CHAIRMAN JABER: Let me ask you a couple of questions on previous slides.

MR. VILLAR: Of course.

CHAIRMAN JABER: With respect to Page 4 -- I'm sorry, it's Page 8, the reserve margin bar graph.

MR. VILLAR: Yes.

CHAIRMAN JABER: And I think as part of your summary you said for the next ten-year period you expect that the margin reserve will remain at about 20 percent. And my question is this: Did you factor into that projection all the factors that would affect demand? You know, in the next ten-year period will it stay at 20 percent using the growth projections and the demand factors that exist today or are you also projecting some of those other things?

MR. VILLAR: This is based on the utilities' load forecasting methodologies that are in place now taking into account the increases in demand on the basis of the forecast. This is based on the 50 percent confidence level forecast.

CHAIRMAN JABER: Okay. But you have taken into account you said the projections in demand by the companies.

MR. VILLAR: The increases in demand for the period.

CHAIRMAN JABER: Okay. And the FRCC doesn't go behind those numbers at all, do you? You really just take the information that the companies give you and incorporate it into a comprehensive review.

MR. VILLAR: Well, the FRCC generally aggregates the company plans. We do make sure there is no double counting of reserves and things of that nature. And one thing that is significant about the reserve margin levels that we have shown here is these are done on a non-coincident basis. In other words, the FRCC just aggregates everybody's plans. If you were to look at the peak demands on a coincident basis, the numbers will probably show reserve margins probably one and a half percent higher than they are here.

CHAIRMAN JABER: Okay. On Page 13, how do you --

MR. VILLAR: Madam Chairman, excuse me for a second. Doctor Green, I think, wanted to add something to that.

CHAIRMAN JABER: How are you?

MR. GREEN: Good morning.

CHAIRMAN JABER: Good morning.

MR. GREEN: My name is Leo Green. I act as the Chairman of the load forecasting task force of the FRCC, and each year we conduct an extensive review of what each utility is saying. For example, we look at the inputs, and we make sure that, for example, whatever one utility is saying is consistent with what another utility is saying, and it is also consistent with what happened in the recent past. For example, we all used the University of Florida population projections, so all of us should have something similar projected. With respect to the economy, we also looked at that to make sure that all the utilities are consistent with their assumptions regarding what the State of Florida looks like.

We compare growths in the past with growths in the future and then there are some factors like the load factor and things like that that should be consistent in history and in the future. After all of that is done, then we say, yes, this looks good. And so it is extensive process that we go through each year.

CHAIRMAN JABER: Out of the census information and out of the University of Florida study that you referred to, it is my recollection that the population percentages actually increased more than we thought. So did you use the new numbers plus an increased percentage? If history holds true, the population will increase by a certain percentage higher every year.

MR. GREEN: That's right.

CHAIRMAN JABER: And did you factor that percentage in?

MR. GREEN: Yes. The census, 2000 census identified some undercountings. That was included. And Mario did not mention it, but this forecast is like 600 megawatts higher than the prior forecast. Part of it is due to that factor, the higher growth in customers and population that we are getting. Another one is the growth and construction of new homes. So that was also built into this new forecast and that is the reason it is slightly higher than last year's.

CHAIRMAN JABER: Okay. And what about technology, the overlay of the technology demand and, you know, how all the studies indicate that every home will have two computers, and, you know, multiple aspects of technology and that that would drive demand even higher. How do you account for that?

MR. GREEN: We have -- for example, I will speak specifically here about FPL, for example. We have people that belong to different trade groups, and we receive projections that a refrigerator will be 20 percent more efficient in five years. We do extensive surveys as to the number of computers in the home, and new technology, and that is built into the end use models which will account for increasing use on a per customer basis. That is on one side. On one side you have the fact that a lot of these technologies are becoming more efficient, which should reduce the consumption. So we have a net effect of both working in the forecast.

CHAIRMAN JABER: Thank you. Commissioner Bradley.

COMMISSIONER BRADLEY: In conjunction with that, have you all given any consideration as to what our increased capacity needs are going to be as it relates to our economic development plan? In addition to the residential needs. And that may change based upon new and advanced technology, but I'm just curious as to what your thinking is as it relates to economic development and business usage.

MR. GREEN: We have a very optimistic outlook for Florida on the economy side now. This has changed since, let's say 9/11. We have been seeing levels of construction of new homes reaching record levels. The amount of money that the banks are loaning for new construction is tremendous. Florida happens to be an extension of New York. We are seeing a tremendous amount of business moving from New York to Florida. There is a lot of people that are moving to Florida just to service the population that is moving here. That is built into the increases that you saw that Mario represented into the forecast. I am not sure I answered your question.

COMMISSIONER BRADLEY: Well, you did somewhat, but I'm thinking about not only service-related businesses, but industrial and other businesses that will be necessary in order to support the new and expanded growth that Florida will be experiencing.

MR. GREEN: Yes, sir. That is looked at on a customer-by-customer basis. We are contacted way before they decide to build or move a specific industry into the area, and we have to be ahead of the game quite a few years. So, for example, something that worked out negatively, telecom loads, we were like two years ahead of the game. We built a lot of facilities to accommodate this load, which because of the way the economy reacted and the way the telecom is doing right now we did not get what we expected. But any type of business that is coming in, one of the first people that they talk to is the electric utilities. And we have assigned customer planners or service account planners that deal specifically with these guys. I, for example, have to be involved with all the local planning committees, and I take that information back to my shop and we incorporate that in our forecast.

COMMISSIONER BRADLEY: Let me ask this question. The data that you have as it relates to the population explosion, have we been able to identify who is going to be moving into Florida and specifically what their profile is going to be? Is this going to be a mixture of retirees, individuals who are young and who are going to be in need of a decent paying job, or is it that companies are going to be coming as a result of the population explosion? But that to me determines a lot of what we need to do in terms of our new and expanded capacity. I mean, if these are going to be retirees who are the same as we have had in the past or if we are going to have young families moving into Florida then that makes for a different type of energy need, in my opinion.

MR. GREEN: That is a very good question. We used to think of Florida as a retirement haven where older people were coming here. All of a sudden the price of houses got so expensive, like over the last ten years the prices of houses doubled. Florida no longer is an affordable state. So we are competing with the rest of the southeast and the southwest for the older population.

However, we are creating so many jobs in Florida that we are attracting now the younger population to Florida. Things like the film industry, high-tech. We are attracting a tremendous amount of young people. If you look at the numbers coming from the University of Florida regarding population, there is almost a shift from the older population to the younger population. We are still getting a lot of older population, but now we are picking up more younger better paying jobs.

And a lot of people that are coming are also coming just to take care of that older population, that still happens. But there is still that big component of younger population that is moving in that we didn't know before.

CHAIRMAN JABER: With respect -- I don't know which one of you can answer that question, but remind me with respect to the margin reserve -- reserve margin. I'm thinking of my water days. The interruptible folks are included in that or not included in that?

MR. GREEN: Yes, they are included in the calculation. To arrive at the firm peak demand we start with a total demand and we adjust for the interruptible and the load control.

CHAIRMAN JABER: So for the year 2011 -- then that is true for the entire ten-year period, you are assuming that the policy of this state will continue to be that reserve margin should include interruptible.

MR. GREEN: Yes.

CHAIRMAN JABER: Okay. With respect to Page 13, I'm not real clear on how you determine the weighted availabilities, what factors go into the determination of availabilities.

MR. VILLAR: The methodology for coming up with a megawatt weighted availability for the region is described in the reliability assessment. And what we basically do is we start from each utility's -- the availability of each utility's forecast. The forecasted availability for each utility's unit, and on a megawatt weighted basis we come up with a utility megawatt weighted availability for that particular utility. Then we take that and we aggregate it into a region-wide megawatt number. So for comparison purposes availability can go up and down on a unit-by-unit basis throughout the time period, and we felt that it would be a lot more appropriate to compare it to have a region-wide number. The only way to really do a region-wide comparison is as described in the reliability assessment report. It provides meaningful information. So you are not comparing one unit went up and another one went down, and one utility might counteract another one. It's probably better to look at it from a regional perspective and that is what we have done.

CHAIRMAN JABER: Thank you. Commissioners, did have you any other questions? Commissioner Palecki.

COMMISSIONER PALECKI: Referring to Slide Number 3 which shows your peak demand, I note that the winter peak demand -- I know that as far as summer peak demand the utilities have done a lot to attempt to reduce the peak demand through conservation. But as far as winter peak demand is concerned, has any concerted effort been made to reduce the winter peak by placing resistance strip heaters and small space heaters with more efficient alternatives, and is that something that the industry may be considering?

MR. VILLAR: I don't know that I have a specific answer for you. I'm going to take a guess at it. Generally what you find is that the replacement for the strip heating technology is a function of cost-effectiveness. And there are places where it might be more cost-effective perhaps to have a gas-fired heater, for example, but there is no availability of gas.

COMMISSIONER PALECKI: I am thinking of even other alternatives.

MR. VILLAR: Yes, there may be other alternatives also. But when companies develop their demand-side planning goals and the programs attendant with achieving those goals they generally look at different technologies and whether or not those technologies are available to the public in a way that would be cost-effective relative to the capacity that may be avoided. I don't specifically have any knowledge as to the technologies themselves, that is a separate group at FPL that does that. But they do on a regular basis look at various technologies and whether those are cost-effective.

COMMISSIONER PALECKI: Well, I think the industry has done an admirable job working on the summer peak, and it seems that there hasn't really been much attention paid to the winter peak. And we have a situation where Florida is a winter peaking state, so that is something that maybe we can look at further. Thank you.

CHAIRMAN JABER: Commissioner Bradley.

COMMISSIONER BRADLEY: On Page 5 you have a projection -- well, you have a current status for 2002 in terms of megawatts. And for 2011 you have a projected number for the number of megawatts Florida would need in order to deal with its energy needs. What do you -- how do you -- what type of population projection are you tying to this figure, and how are you separating out the business needs from the residential needs? And that may not be a question you can answer at this point, it just may be something we can talk about later.

MR. VILLAR: That may be a question for Leo.

MR. GREEN: I'm sorry, Commissioner, could you repeat the question, please.

COMMISSIONER BRADLEY: Okay. On Page 5, for 2002 you projected we are going to need 44,735 megawatts for this year. That is the current capacity in order to serve Florida.

MR. GREEN: That's right.

COMMISSIONER BRADLEY: In 2011, you predict that we will need 56,997 megawatts. And I'm just wondering how you are breaking that out for the various categories of business, industrial, and residential, and what are you projecting the population to be?

MR. VILLAR: Leo is going to talk about the forecast and what is included in there. What you have here is this is the available capacity on the system. In other words, the number of megawatts of generating resources that may be available to serve the load.

COMMISSIONER BRADLEY: Uh-huh.

MR. VILLAR: This is only the iron in the ground, if you will, that is available to serve the needs, what is forecasted to be available in 2011. It doesn't speak to how you got to the demand or the breakdown between residential, commercial, et cetera, which is more along the lines of forecasting.

MR. GREEN: This is the total capacity out there to serve the demand. From this number we need to take out a percent that is reserved, we need to take out a percent that is line losses, and then you arrive at the number that the customers will be demanding. We have in Florida, we have three major components which is the residential, commercial, and industrial. The industrial growth in the State of Florida is very slow, very slow. In fact, most of the growth that we see is because of new construction, okay. A temporary meter for a home that is being built is classified as an industrial customer. Most of the growth is coming there.

However, the commercial sector is experiencing the fastest growth out of those three sectors. The residential is growing at about what the customer population is growing, plus an increasing use per customer. On the average, a customer will use anything from one to one and a half percent more per year, and the population is projected to grow at about 1.8, 1.9 percent.

Customers will grow a little more than that because we can have customer growth without having population growth. When my daughter moves out and create her own home, I get a new customer without changing the population. So customers will grow a little faster. Our bread and butter, however, in

Florida is the residential customers, followed by the commercial sector and then the industrial sector. The fastest growing sector being the commercial sector. That would be like hotels, restaurants, universities, hospitals, businesses.

CHAIRMAN JABER: Commissioner Bradley, if I may. I think also though -- if I could try to get an answer to your question in a different way. The available capacity for 2011 your conclusion is will be sufficient to meet the demand for 2011. So I think part of the question is what is the corresponding population number associated with the demand projected for 2011. That was it, right?

MR. VILLAR: And if you see, Commissioner, the slide that you were referring to before, this one which shows the capacity mix of 57,000 megawatts, roughly, if you look at Page Number 3, you will see what the actual forecasted demand is. It is somewhere in the order of 46,000 plus megawatts for the summer. So the difference between the two is basically the reserve margin that is available in the state. And the actual population is embedded within the forecasted demand on Slide Number 3.

We do have a number of customers in the load and resource plan on an average basis for the aggregated state in 2011. I'm trying to see whether I can find one column here that shows all the customers, but that is rural and residential, it doesn't include commercial and industrial. I'm trying to see if we have a total number. There is a breakdown in the load and resource plan, it is FRCC Form 4, Commissioner, and it shows the number of customers for each category. Unfortunately, I don't have one that adds them up, but we have for 2011, 8,137,000 plus rural and residential customers on an average basis, and then about a million commercial customers, and about 30,000 or 31,000 industrial. And then some other minor categories. So you do have in the information that the FRCC compiles a breakdown of the customers by classes on an average basis by year.

CHAIRMAN JABER: Thank you. Commissioners, any other questions?

COMMISSIONER PALECKI: Just one further on Slide Number 5. Should we be concerned about the reduction in nonutility generation from 9 percent today to 4 percent in the year 2011? I mean, that is a reduction of over 50 percent.

MR. VILLAR: Well, one is you have a much higher base. So just the fact that you have a much higher base is going to reduce the percentage unless that number is growing. Second, this is not capacity that is going away necessarily unless the plant is totally economically -- the capacity may still be available in the state, so it's just a matter of whether it is more cost-effective or more economic than some other capacity to be contracted on a firm basis.

Like I said before, this only represents what is under contract on a firm basis to utilities at this point. If a contract is ending and that capacity is cost-effective to the utility and it makes sense, it's in the best interest of the ratepayer to contract for it on a firm basis, I'm sure the utilities would pursue that. If the capacity is not economical from that perspective, it is still available to sell in the market on an as-available basis like many QFs do nowadays.

COMMISSIONER PALECKI: Well, if we look at the pie for year 2011, basically what we are seeing is 51 percent of the pie is utility generated natural gas, mostly combined cycle, I would assume, generation. Are we putting too many eggs in one basket? I look at the pie for 2011 and I have some concerns about fuel diversity and about diversity in who generates. We are going from a pie that we see in the year 2002 that seems to have more diversity, a higher level of generation by nonutility generators, a gas portion of the pie that is approximately one-third to the year 2011 where we have more than half of the pie being utility-generated natural gas, and just very small portions being allocated to other sections. Should we be concerned about fuel diversity and generation source diversity?

MR. VILLAR: Well, I think every utility looks at its mix, its resource mix on a regular basis when they do their planning. I know we do for FPL, and we pursue that which is more cost-effective to our customers. I think from the standpoint of the new generating capacity additions throughout the country, natural gas has been the preferred fuel of choice from an economic perspective for quite sometime now. So I don't think we are any different than anybody else either as a state or on an individual utility basis. But by the same token, I know at FPL we are concerned with the amount of gas that we are going to be dependent on and perhaps the attendant volatility. And when we do our planning we look at what may be available out there, and what options we may have, and the cost-effectiveness of those options to see if there is anything that can be done. But it is an issue that I think we will continue to deal with in the future, Commissioner.

CHAIRMAN JABER: Mr. Wiley.

MR. WILEY: I'm Ken Wiley with the FRCC. I would like to elaborate a little bit on that question. Your specific question was is this presenting a problem to us, and I would say that right now it is not presenting a problem to us. Is it something we should be concerned with? I think it is something that we need to think about from a policy perspective in the state. This was discussed quite extensively at the 2020 Commission. As a matter of fact their report spoke to this, about us getting into a picture -- and they we are looking out to the year 2020, nine years beyond this -- and they were concerned about a big lack of fuel diversity looking at that year 2020. As a matter of fact, they even went so far as to put in that particular report something to the effect that this was a policy decision that this state was going to have to look at into the future as to whether or not this Commission, as an example, might be looking at not always approving the least-cost new generation alternative because of fuel diversity considerations.

And so I once again say that this was based upon a look at a 20-year period. And I think that this ten-year look that we are seeing right now substantiates their concern for the 20 years that as a state we need to continue to watch this. And it is a big, it is going to become a big policy issue unless we see some major shifts.

COMMISSIONER PALECKI: I guess part of that concern also is that we are seeing the same trend all over the country, and as we see all 50 states in the country get on the natural gas combined cycle bandwagon, I guess we could see some unforeseen spikes in gas prices coming in the future, couldn't we?

MR. WILEY: I'm not a gas price expert, but having lived through 1972 and the embargo on oil, we saw spikes back then on supply. But I am also involved in a lot of national activities at the North American Electric Reliability Council, which is the national equivalent of FRCC, and this is an issue that we are addressing up there, looking into the next ten years and trying to call attention to this growing reliance, and I wouldn't say overreliance yet on natural gas, nationally. The FRCC has become interested. I will not say concerned yet, but interested in the pipeline capacity into the state as we see this larger dependency. We have gone from 10 percent gas five or six years ago to about 30 percent of our gas -- excuse me, electricity coming from gas today to 50 percent in 10 years is the projection, and we have concerns about ensuring that the pipeline reliability to be able to supply this gas into Florida under outage or contingency conditions as we call it is, in fact, going to be there.

And we have started an analysis of trying to educate ourselves here in the state on how do pipeline companies develop and plan their gas pipelines. Many of you are familiar that when we plan our transmission lines in this state, we do a lot of simulation of what if we take these lines out while this one is on maintenance, can we still ensure that the electricity gets through to the customer. And we are now trying to ensure that our planning techniques for our transmission and generation system are, in fact, in sync with the same way that these gas pipeline companies plan the capability of their gas pipelines at peak times of use.

And so the FRCC has just begun this particular type of analysis and discussion with the gas pipelines. As a matter of fact, we would welcome a member of your staff to participate in this education process that we are going through right now.

COMMISSIONER PALECKI: What about coal and nuclear units, do you think it is time that we start looking at the possibility of future coal and nuclear units in the State of Florida?

MR. WILEY: I don't feel qualified really to answer that question, Commissioner.

COMMISSIONER PALECKI: Thank you, Mr. Wiley.

CHAIRMAN JABER: Thank you.

Commissioner Bradley, go ahead.

COMMISSIONER BRADLEY: One question. What is driving the fuel diversity issue and the fact that some fuels are viewed as being decreasingly involved, and some are being viewed as increasingly more involved in meeting the energy needs of Florida? Gas, for example. Coal is decreasing, oil is decreasing. And I agree with you, you know, we need to pay close attention to the fuel diversity issue. Because if you become heavily dependent upon one, then that means that if some unforeseen occurrence happens, it might have an adverse impact upon our ability to generate and meet our capacity needs? Maybe that question was too long. Maybe I need to make it shorter. What is driving our diversity?

MR. VILLAR: The short answer is basically economics at this point. It is what is dictating the mix of units that is being put into utility plans at this stage. That doesn't mean that at some point if you see that there is going to be an over-reliance on any one particular fuel, one of us might not come before this Commission and say in spite of the economics showing that a gas-fired plant may be the most economical from a planning perspective, we are concerned about increased reliance on this particular fuel and we might come before you with a request to approve something that might be a little slightly higher on an economic basis.

For example, a coal-fired plant has very high upfront capital cost. Its fuel clause is lower, but its heat rate is also higher than a combined cycle unit. So when you look at the total economics, you have to balance all of those factors out.

COMMISSIONER BRADLEY: One other question. To what extent have you explored new and expanded technologies to assist in how we use our fuel sources in order to increase our capacity?

MR. VILLAR: We are always monitoring what new technologies may be out there, but there is a lot of those technologies that are not suitable to Florida. For example, there is wind generation that my company is involved in in some other areas. Unfortunately, the winds in Florida won't support that kind of stuff. There is developments in fuel cell technology, but they are not at the level now where they are commercially feasible or the cost-effectiveness of those sources are at the level where we feel that we ought to be committing ourselves to it, et cetera. But I think a lot of utilities on a fairly regular basis look at all the different technologies and the penetration rates and the economics associated with those and incorporate them into the plans as they become appropriate.

CHAIRMAN JABER: Thank you. Thank you for your participation today. We really appreciate it. Staff, who is our next speaker?

MR. HAFF: Mr. Villar, are you going to be presenting for Florida Power and Light, as well?

MR. VILLAR: Yes. I didn't know if I was next or if Power Corp was next.

MR. HAFF: We will just go on and take you next since you are already set up and everything. So if you want to go on, we will start with Florida Power and Light Company.

MR. VILLAR: Commissioners, again, my name is Mario Villar, I am manager of resource planning for Florida Power and Light. And I will give you a very brief overview of FPL's ten-year site plan. What I will take you through is the resource additions that FPL plans for the period 2002 through 2011, and give you the result of our loss of load probability analysis and reserve margins.

The cumulative capacity additions that FPL has planned for the period of 2002 through 2011 are roughly 6,400 megawatts of summer capability projected through 2011. That is a significant increase from the ones shown in prior plans, both as a result of -- one is a different planning horizon, of course, and also the fact that we have seen some increases in load like Leo described during that time period.

We had shown in the 2000 plans roughly 4,500 megawatts of generation and now we are up to about 6,400 megawatts of generation. Out of those 6,400 megawatts, roughly 1,200 megawatts are as a result of changes to or repowering of some of our existing plants. I think if you look at the 1,199 that are shown there, the bulk of those megawatts are associated with that Sanford conversion repowering which is supposed to come on line in 2003 or completed in 2003. And then new units, roughly 6,600 megawatts planned between now and 2011, and some existing power purchases that are expiring to the tune of about 1,300 megawatts or so.

The bulk of the power purchases today is a Southern Company contract that we have that expires in 2010. And at this point we have not decided how we are going to replace that. We are showing that it is being replaced by combined cycle capacity. We could try to negotiate to extend that contract or do something else.

The actual unit additions that we will be adding through the period are two combustion turbines in our Fort Myers facility in 2003. In 2005 the Manatee combined cycle unit and the conversion of Martin combustion turbines to combined cycle, and those items are before you for the 2005/2006 time frame as a result of a filing following our RFP. And then following that, we have four combined cycle units unsited at this point in 2007, 2008, and then skipping 2009 and two more in '10 and '11.

This slide just basically represent FPL's DSM goals, what we have forecasted for the period through 2009. There is only goals that have been set up to that point, and I think that there is a review of the goals scheduled for next year. And we have exceeded our goals through 1999, the ones that were set before.

FPL's planning criteria consists of two different methodologies. One that I described before very briefly in the FRCC presentation, which is the loss of load probability analysis. We do it for the FPL system because it is part of our criteria, and we also have a reserve margin analysis. Both methodologies we considered them to be equally important, but in FPL's system for quite a number of years now reserve margin has been the driving factor as opposed to LOLP.

The LOLP criteria is one day in ten years, the maximum loss of load probability, and the reserve margin FPL has traditionally used a minimum of 15 percent reserve margin, and in 1999 we agreed with the Commission to go to a 20 percent reserve margin starting in 2004, in the summer of 2004. The results of our analysis are shown in this slide. The LOLP continues to be extremely low, and that is a factor of a number of things. One, the fact that we continue to have extremely high levels of reliability for our units, existing units, low forced outage rates, high availability associated with those units. And we have quite a number of units in the system. All of that contributes to the reliability from the LOLP perspective.

The reserve margin numbers are shown on the right for both summer and winter, and you see there that the reserve margin numbers starting in 2003 are forecasted to be above the 20 percent level, which is the number that we are planning starting in the summer of 2004. The winter numbers exceeded by a significant amount.

In summary, FPL's system on the basis of our results for both loss of load probability and reserve margins is projected to be better than the planning standard. That concludes my presentation.

CHAIRMAN JABER: Commissioners, do you have any questions? Okay. Thank you.

MR. VILLAR: Thank you.

MR. HAFF: Thank you, Mr. Villar.

MR. VILLAR: Yes, Mr. Haff.

MR. HAFF: There are no questions. You weren't expecting that, were you?

MR. VILLAR: Not really.

CHAIRMAN JABER: Are there questions we should be asking you?

MR. VILLAR: No.

CHAIRMAN JABER: Florida Power Corp.

MR. CRISP: Good morning, Commissioners and staff. My name is Ben Crisp, I am director of system resource planning for Florida Power Corporation. I would like to give you an overview of our 2002 ten-year site plan.

To start off with I will go through our reliability criteria. Florida Power operates with a 15 percent minimum reserve margin currently. That will increase to a 20 percent reserve margin criterion. That was agreed to in the generic reserve margin docket. We also comply with a .1 LOLP day per year or one day in ten years loss of load probability. We will implement our 20 percent reserve margin criterion in the winter of 2003 and 2004. Our plan currently operates well within LOLP requirements.

Our next slide shows our load forecast for the ten-year time frame, and you see a solid line going approximately halfway through the graph. To the left of the midpoint is historical, to the right of the midpoint is projection. You see the trend continuing at a consistent slope. You see some reductions in the approximately 2002/2003 time frame. Those have to do with wholesale contract expirations.

Our load forecast process consists of 25 years of historical data analysis. We have three primary weather stations that we analyze in St. Petersburg, Orlando, and Tallahassee. We use a weighted average of each of those weather station data points. We include demographic, economic, and business driver analysis to come up with our overall drivers for our load forecasts. We have noted the same change in usage patterns that Doctor Green referenced with increases in growth and increases in usage per customer.

We utilize a bottom-up approach including analyses of retail and wholesale load as well as inclusion of DMS. Our demand-side management resource program is consistent with our currently approved DSM plan. It complies with Commission established goals through 2009. We believe that demand-side management is a valuable resource when used appropriately, and I say that because Florida Power Corporation in the past has included a considerable amount of DSM in its reserve margin and we are working to balance the amount of reserves between physical reserves and DSM.

Drivers of our new capacity additions for Florida Power include primarily retail load growth. That affects us in two areas. It affects us specifically with our residential retail growth that we serve. It also affects us through existing wholesale contracts which we provide to other load serving entities who are experiencing that same retail load growth.

The bottom bullet, in order to support FRCC reliability, Florida Power has agreed to the 20 percent reserve margin, as I said before. And that is another driver of our expansion.

These are the units that you will see added to our ten-year site plan. At Intercession City in Units 12 through 14 there is a firing temperature rate that will result in 12 megawatts. Peaker Unit Number 15 is a 184-megawatt combustion turbine. Peaker Unit Number 16, 184-megawatt combustion turbine, November of 2004 and 2008 respectively. And you see the Hines Energy Complex combined cycles that you have seen over the years which are used to fill our intermediate load gap.

Commissioner Bradley, you had asked questions about coal versus combined cycle. We have done a number of scenario analyses around coal and combined cycles. It costs twice as much to build a coal plant, as Mr. Villar was stating, than to build the combined cycles. From the economic standpoint that is a good decision. We went back and did scenario analyses on what prices would gas have to reach. What prices would gas have to sustain a price level at in order to justify the building of a coal plant, and we are seeing that gas would have to reach a consistent price of $5 to $6 an MMBtu while coal stayed at approximately $1.80 an MMBtu. So you are talking about a delta of anywhere from $3 to $4 an MMBtu price difference in the fuel to offset those significant increases in price of a coal plant.

We continue to look at nuclear technology. But currently, as Mr. Villar said, the economics of the gas plants justify the addition of combined cycles.

MR. HAFF: I have got a question, Mr. Crisp. That slide back up for me, please. Why are the combined cycle sizes for years four, five, and six different from two and three?

MR. CRISP: Two and three are the specific quoted performance levels winter ratings for the contracted units. As you know we are going into construction on Hines Unit 2, so it has been locked in at a specific rating. And three, as well. Units 4, 5 and 6 are generic ratings that come out of EPRI tag data that are generic ratings, if you will.

MR. HAFF: Okay.

MR. CRISP: A quick overview of each one of these additions that are currently in the construction phase or are approaching construction phase. Hines Power Block 2 is our combined cycle unit that is necessary to serve intermediate and base load. Site certification has been approved, ground breaking was on March 28th. Equipment delivery is scheduled for February through April of 2003. The project is on schedule for the December 2003 commercial operation.

The Intercession City P15 combustion turbine, the peaker addition. That is necessary to serve peak load increases. It supports our transition to increase supply-side reserves. We are currently securing equipment and site requirements, and the project is on schedule for December of 2004 commercial operation.

COMMISSIONER PALECKI: Let me ask you a question. This relates both to this slide and also one of your earlier slides where you showed your seasonal peak demand. And I note that your winter peak is very much higher than your summer peak, and it is my understanding that serving the winter peak is pretty much a money loser for the utilities. It's very expensive load to serve. Why haven't the Florida utilities done more to attempt to reduce the winter peak demand? I know you have done a great job on the summer peak demand, but it would seem that this winter peak is something that could probably be dealt with rather easily with more efficient heating technologies.

MR. CRISP: We do look at and evaluate heating technologies. One of the other things that is we look at, Commissioner Palecki, is our balance of DSM programs. That winter peak is a spike and it consists of maybe -- a very small percentage. That early morning spike lasts such a short period of time it is a natural use of DSM. So we look at DSM utilization in the wintertime. We look at DSM utilization less in the summertime. So what we are doing is ramping down our

DSM programs in the summertime as much as possible while maintaining a focus on the winter peak for DSM utilization. We also do have programs where we are looking at improved technology on heat pumps and other types or methods of improving the efficiency. We have nondispatchable load reduction programs, insulation, double windows, things like that.

COMMISSIONER PALECKI: Thank you.

MR. CRISP: Hines Power Block 3 is another combined cycle addition. The RFP for this combined cycle was issued in November 2001. Hines 3 has been identified as the most cost-effective alternative to meet the customers' needs. Need petition filing is scheduled for September 2002 with a December 2005 commercial operation date. The bar graph shows simply how each one of the combined cycles and the two peakers come into play over the ten-year time frame.

A quick summary of our projected reserve margins for winter and summer. And in summary we would propose that our plan is suitable for planning purposes for Florida Power Corporation.

CHAIRMAN JABER: I don't know what slide it was, but just generally speaking, I think you said as it relates to the DSM conservation goals, that you are trying to balance out the conservation goals with the reserve margin.

MR. CRISP: Correct.

CHAIRMAN JABER: What percentage of the conservation goals or the conservation factors are included into your reserve margin percentage?

MR. CRISP: This slide shows 100 percent of our winter resource reserve requirements. I don't believe it is included in your packages, but as you will notice, you will see that the pink part of the bar chart is the supply-side reserve contribution, and you see how low it is in the wintertime currently. The bulk of reserves is in DSM.

What we are trying to do for the wintertime is get it up to approximately -- get our supply-side reserves up to approximately 50 percent. The reason for that is we carry about 1,500 or so megawatts of reserves. What we would like to do is be able to cover the outages of a single large unit or the outage of a couple of small units with physical reserves rather than have to lean on DSM to cover forced outages. So that's why you see us moving upwards into the 40, 50 percent in the wintertime. We still like winter DSM because it is a very effective way of clipping the peaks in the wintertime for that one hour in the mornings, in the early mornings on cold mornings.

CHAIRMAN JABER: I can't see the years there and the numbers, so if you could just tell me what your internal goal of having at least half covered in supply resources.

MR. CRISP: Right. What we would like is about 700 megawatts to 750 megawatts of physical reserves. That will give us the ability to cover a coal unit outage or possibly a coal unit outage and peaker outage at the peak, at the point of peak.

CHAIRMAN JABER: But by when, what is your target date?

MR. CRISP: By 2005, 2004/2005.

CHAIRMAN JABER: Can you file or submit this chart to us after the workshop?

MR. CRISP: Certainly. We would be happy to.

MR. HAFF: Do you have a corresponding chart for summer resources, as well?

MR. CRISP: Yes, we do. Summer is a different issue altogether because of the breadth of the peak. The peak lasts for an extended period of hours in the afternoons and evenings. And for that purpose DSM is not considered as robust a program to cover reserves. So we would rather operate in the 60 to 70 percent of physical reserves during the summertime. That is why we are shaping summer DSM versus winter DSM and shaping our fleet to be able to cover the respective peaks with as much physical reserves as possible in the summertime. That corresponds to a higher level of megawatts, and we will be happy to get those numbers to you.

CHAIRMAN JABER: Thank you.

Commissioners, do you have any questions?

Thank you, Mr. Crisp. Staff, you didn't have questions, did you?

MR. HAFF: No.

CHAIRMAN JABER: Thank you.

MR. HAFF: Next on the agenda is Gulf Power Company.

CHAIRMAN JABER: I would just note that the presentations are getting more colorful. So, TECO, the pressure is on.

MR. POPE: And with less glare.

CHAIRMAN JABER: We're read when you are.

MR. POPE: Good morning, Commissioners. My name is Bill Pope, P-O-P-E, with Gulf Power Company. With me is Mike Marler, who does our forecasting for Gulf Power Company. Mr. Marler will be presenting the first few number of slides because they do deal with Gulf's load and energy forecast.

MR. MARLER: The first slide presents our summer peak demand projections. Historically we have been growing at 2.2 percent over the past ten years, and we are looking at a peak demand projection of 1.1 percent. It's slightly lower than last year's projection of 1.4 percent. Our winter peak demand growth over the past 10 years has been 3.8 percent. Our projections over the next ten years is very similar to last year's forecast. The new forecast is at .8 percent and last years was at 0.6 percent.

The net energy for load projections historically have been growing 2.7 percent, and over the next ten years we are looking at a growth rate of 1.3 percent compared to 1.5 percent from last year's projections.

The next slide presents our DSM impacts over the past ten years and the next ten years. The previous ten years we conserved 288 megawatts of summer peak demand due to DSM programs, which lowered the growth rate from 2.5 percent historically to 2.2 percent. And over the next ten years our incremental DSM savings will bring the total up to 461 megawatts by the end of the ten-year period. It will decrease the summer peak demand growth from 2 percent to a net of 1.1 percent.

Our winter DSM programs historically have lowered our growth from 3.9 percent to 3.8 percent. Cumulative savings up through 2001 is 334 megawatts and over the next ten years it is projected to grow to a total of 532 megawatts. That will lower the winter peak demand growth from a total of 1.4 percent to 0.8 percent. And the energy reductions due to DSM programs, over the past ten years the growth rate would have been 2.7 percent, which is very similar to the net after DSM 2.7 percent. There has been a reduction of approximately 613 gigawatt hours per year in 2001. And by 2011 that is expected to growth to 888 gigawatt hours per year which will lower the projected growth rate from 1.4 forecast to a net of 1.3 percent.

MR. POPE: Now, Commissioners, the next slide -- and I apologize for being so busy, but this really, the focus of this slide is on the far right-hand side where it shows Gulf's reserve margin in percent and Southern's reserve margin. As you remember, Gulf Power Company plans as an integral unit of the Southern Electric System, and as such we are embodied in that reserve margin on the right-hand side. But I did want to give you all the figures that led up to that in case you wanted to have them for reference. And finally --

CHAIRMAN JABER: May I interrupt you there. I need to better understand that. What does that mean?

MR. POPE: The planning and reserve margin part?

CHAIRMAN JABER: No, with respect to your reserves are part of the Southern reserves.

MR. POPE: We are approximately 6.8 percent of the Southern Electric System with regard to peak load demand, summer peak load demand. The Southern Electric System as a whole plans its electric system as an integrated body. And what Gulf Power Company does is we have a certain portion, 6.8 percent of it or so in demand growth that we have to basically select the way that we want to serve that load. Whether it be by power purchases in the short term or whether it be by new generation. And as Mike pointed out, we do have DSMs that make up a part of the plan to meet those reserves, or the growth of our customers. So our planning is integrated as a large unit.

And we benefit from being a small fish in that big sea because the Southern Electric System can do things. We do some reserve sharing, we have a thing called the company interchange contract which allows us as a small unit to benefit from the big additions that the Southern Electric System puts in from year to year. So they can smooth their increases and their needs over time and we can benefit from them.

CHAIRMAN JABER: So did that have anything to do with why Gulf did not volunteer to maintain the 20 percent reserve margin? To agree to maintain for Gulf Power only 20 percent reserve margin, would that have affected your ability to have access to the Southern reserves?

MR. POPE: Are you referring to the Peninsular Florida's voluntary 20 percent?

CHAIRMAN JABER: Yes.

MR. POPE: Actually we came and started that process, I believe it was under Chairman Johnson at the time, and it was deemed at that time to be a peninsular issue, and Gulf was not incorporated into that process. We weren't asked to participate.

CHAIRMAN JABER: Has there -- and I apologize for making you give me this historical perspective. It really was just before my time.

MR. POPE: All right.

CHAIRMAN JABER: Has anyone ever asked or has the company internally discussed whether Gulf Power should voluntarily agree to participate in maintaining a 20 percent reserve margin?

MR. POPE: It never has become an issue, Commissioner. Because of the tremendous benefits of Gulf Power Company being a relatively small -- and the smallest IOU in the state, the benefits we receive from being a part of the Southern Electric System and being such a large system and also half of the Southern Electric System's generation and load is in the eastern time zone, and the other half is in the central time zone, there is some tremendous diversity benefits there, as well.

CHAIRMAN JABER: Would you lose any of that, though, if you agreed to increase your reserve margins to 20 percent? Would any of those benefits be lost?

MR. POPE: No, but it would probably cause our customers to pay more than necessary. The benefit we get from having the lower reserve margins is our customers don't have to pay for those capacity resources that we would otherwise have to do.

CHAIRMAN JABER: And you participate though in the wholesale energy sales, though. You sell your excess capacity and participate in our incentive program there.

MR. POPE: As a part of the Southern dispatch pool, yes, ma'am, we sure do.

CHAIRMAN JABER: So to the degree there were any increases to customers associated with that, I suppose there would be a wash to some degree.

MR. POPE: That is correct.

CHAIRMAN JABER: You know, I would very much like to talk to Gulf Power about that more and ask that you all consider voluntarily maintaining a 20 percent reserve margin. There may be some other reasons I'm just not educated on, but if you could take back that message that would be great.

MR. POPE: And the message is you would like further discussions with us about possibly joining the other utilities?

CHAIRMAN JABER: Yes.

MR. POPE: I certainly will do that.

COMMISSIONER PALECKI: I have a question with regard to the year 2007. Should we be concerned that the reserve margin goes down to a 13 percent level in that year, and especially do we need to be concerned if there is a severe winter peak that affects the entire southeast of the United States?

MR. POPE: Not particularly. Let me address each of those issues separately, Commissioner Palecki. With regard to the lower reserve margin of 13.2 percent, historically you will see from previous ten-year site plans we have had reserve margins below 10 percent for Gulf Power Company. But because we do share in the Southern Electric centrally dispatched pool it has not been an issue because of the sharing of capacity that we have through our IIC. So that has not and we do not see it to be a problem in the future at this time.

With regard to winter peak and how we participate on the state level, Gulf Power Company and Southern Electric System is not a winter peaking -- are not winter peaking utilities. We typically have quite a bit of generation reserves available in the wintertime for winter peaking and have in the past through our tie lines shared and sold power to the peninsular when emergencies have arisen. So we are always -- as integrated utilities we are always available to share what we have. And the Southern Electric System typically does have more generation during the wintertime because we are not winter peaking.

COMMISSIONER PALECKI: Thank you.

COMMISSIONER DEASON: Could I back up for just a moment? I understand, you know, the question that was asked concerning Gulf's need, or at least to consider participating in the Peninsular Florida requirement as it comes to reserve margins. And there was a question asked that to the extent that there was additional capacity added that it could be marketed at the wholesale level and it would be a wash. I'm not so sure that it would be a wash. It would have the tendency to help offset those additional costs of additional capacity, but whether it would be wash or not would, of course, depend on the wholesale market and what prices would be available in there. Let me ask is my understanding correct on that?

MR. POPE: I believe you are correct.

COMMISSIONER DEASON: So there would need to be a consideration of the additional cost balanced with the perceived increase in reliability that would come about by that.

MR. POPE: That is correct. And that is where you --

COMMISSIONER DEASON: I think that was implicit in your question.

MR. POPE: When you get into further discussions about that, that would be things that you would specifically address is how those additional capacity resources would be treated because you would want them to be available when you need them and at other times they would be sold off. And what the market values would be at that time, that is a totally different subject.

COMMISSIONER DEASON: That would all go into the consideration.

MR. POPE: That is correct.

CHAIRMAN JABER: And I would just note that that is exactly what went into the consideration with the other IOUs participating. It is a question. You know, like I said, I may not be completely educated on why it wouldn't work for Gulf

Power, so I will keep an open mind there. But it just sort of flies out at you that Gulf Power has not voluntarily agreed to the increased reserve margin.

MR. POPE: That is correct, and there are a number of other differences. Not just geographic, but in the makeup of reserves in the peninsular as opposed to Southern and Gulf Power Company.

The final slide, Commissioners, just basically outlines the additions and retirements for Gulf Power Company over the next ten-year period. And that starts with the addition of Lansing Smith Unit 3 which went commercial actually on April 22nd, 2002. That is a 574 megawatt combined cycle unit. Next we have the retirement of Lansing Smith Unit A, which is a 32 megawatt Number 2 lighter oil-fired CT. December 31st, 2006 is when it retires. The next unit addition scheduled for Gulf Power Company at this time is the addition of another combined cycle unit. Excuse me, I'm sorry, a combustion turbine in 2008, a 157-megawatt combustion turbine in 2008. And those are the only unit additions and retirements that Gulf Power Company has over the next ten years.

CHAIRMAN JABER: Thank you. Commissioners, do you have any questions? Staff? Thank you.

MR. HAFF: Thank you, Mr. Pope.

CHAIRMAN JABER: Commissioners, do you need a break before the TECO presentation? Yes. How about a ten-minute break.

(Brief recess.)

CHAIRMAN JABER: TECO.

MR. CURRIER: Good morning, Commissioners. My name is John Currier, Director of Asset Management, Tampa Electric. In a normal year our director of resource planning would give this presentation. That happens to be Bill Smotherman. Bill is the proud parent of his second daughter this week, so he asked if I would step in for today.

CHAIRMAN JABER: Great.

MR. CURRIER: I also want to mention, I think we are going to uphold your expectations on colors as we get into these pie charts.

CHAIRMAN JABER: Yes. I was shown this one page. We are not giving out awards today for that, sorry.

MR. CURRIER: Okay. Tampa Electric will begin with its total retail peak for summer, and we have shown a comparison of last year's forecast to this year's forecast and we are expecting a slight increase in expected load from last year. And as you line-up historical plots, or points, or peaks, you can see that is a fairly linear growth throughout time.

The second page is the same plot with our winter profile. Obviously winter temperatures vary year to year, but, again, as you line up a regression you can see that it matches fairly well with our historical trend. And also we expect this year's load forecast is a little higher than last year's expectations.

On the third page we reflect our summer DSM resources. And if you look at summer of '02 we have approximately 661 megawatts of total DSM, which about 50 percent of that is curtailable or dispatchable DSM load management and interruptible. And as you go out through time, we have got a little bit of growth in our DSM profile and probably about 45 percent of that will be dispatchable DSM. Interruptibles continue to decline through time, and that is generally due to the fact that the phosphate industry in the Tampa region continues to go down, and some of it is also moving farther south out of other territory.

The next page might help Mr. Palecki in his question earlier. We have the winter DSM resources, and you can see it is almost twice as much DSM in the winter on the Tampa Electric system as the summer months. Most of it is in the yellow color which is the passive conservation activities in the market and most of that is through the state requirement for heat pumps for winter or for electrical heating purposes. And so you can see that is approximately -- and that continues to grow and it is up to 1,300 megawatts by the time we get to 2011.

Our major assumptions for capacity are listed on this next page beginning with our major construction program we are on today. Our first set of assets called Bayside 1 will go in service May of '03. It is a total of 709 megawatts of summer rating. It is three CTs repowered with our Gannon 5 steam turbine.

The second Bayside addition is listed here to go in service in May of '04. We actually have moved that schedule up by four months and expect it to come in in December of '03. The reason for that is the economics of scale, the fact that we have such a major construction program going on we felt that that matched best in the timing of all the resources and labor costs required to bring that machine in service.

Bayside 2 is a four-on-one repowering, and it will match up with your Gannon 6 steam turbine at Gannon. Also as part of are our consent decree both with the Department of Environmental Protection and the EPA, Tampa Electric will no longer be allowed to burn coal or be permitted to burn coal at Gannon Station as of December 2004. So at that point we will have four machines that will go into long-term standby. Two of those machines, Gannon 5 and 6, will be repowered and be a natural gas-fired facility.

The economics of converting this coal plant up to today's environmental standards for both SO-2 and NOx we believe was just cost prohibitive. Partly because we had no land for scrubbers and the NOx requirements for these units would have been very cost prohibitive.

Hookers Point Station will be fully retired at the end of this year, December of 2002. And then finally we want to comment that unlike the previous couple of years, we do not have any unspecified purchased in our ten-year site plan.

For system reliability, we show the ten-year period based on the summer reserve standard, and you can see that we will move to the 20 percent standard in the summer of '03 as we bring Bayside 1 in. And then with Bayside 2 we actually are going to see upwards of near 40 percent reserve margin, and that is summer.

The following summer, though, we put the four coal machines, Gannon 1 through 4 on long-term standby so that drops us down to the 21 percent. And we consistently stay just above 20 throughout the summer months. In the winter months you can add about 3 percentage points onto these numbers to give you that sense of our winter reserve margin.

The next set of pie charts is our capacity profile based on the summer, and you can see we are going from a composition of Big Bend and Gannon to a composition of Big Bend and Bayside. From a pure megawatt view of the world, those two stations are equivalent in size, particularly if you look at the winter page on the next page.

Our future capacity additions in our site plan are all CTs, and I believe we have five CTs beginning in 2005 in the plan.

Moving on into generation by fuel type. Tampa Electric historically has been less of a fuel diverse system, we have been 98 percent coal for a number of years. We continue to be that way in '02, but as we fully -- I will say almost reinvent the supply system, you will see that we are moving to a balance between the coal resources and natural gas resources on the system.

The Syngas is listed here, which is the blue sliver, is what we serve Polk 1 with. It is a combination also of coal and pet coke creating synthetic gas.

And, in summary, Tampa Electric's ten-year site plan provides adequate system reliability and fuel diversity for its customers.

CHAIRMAN JABER: Thank you.

Commissioners, do you have any questions of TECO? Staff?

MR. HAFF: None.

CHAIRMAN JABER: Thank you very much.

MR. CURRIER: Thank you.

MR. HAFF: We will get into the municipals and co-ops now. And first I have Florida Municipal Power Agency.

MR. CASEY: Good morning, Commissioners. I am Rick Casey, the planning and contracts manager with Florida Municipal Power Agency. And I've got a few slides to summarize our ten-year site plan this year. For the new Commissioners on staff, if you will bear with me I've got one or two slides that speak to our structure which is a little bit different.

This first slide lays out the five power supply projects that we have active, and the All Requirements Project is our largest and most active project where we spend 99 percent of our time planning. Through December 2001 we had 13 member cities in the project, and as you will see from the next slide, we have grown once again this year. We are proud to say that Lake Worth and Kissimmee have both decided to join the All Requirements Project this year, so now we have 15 cities. We will speak to that more in next year's ten-year site plan in detail, but we are continuing to grow.

Just to give you a perspective on what our summer peak demands look like, 2001 actual was 965 megawatts. Our 2002 projected number was 1,024, and with Kissimmee and Lake Worth in we expect to see a peak in 2003 summer of 1,408, which is about 30 percent more demand.

Significant changes in this year's ten-year site plan as compared to last years. Our 2002 summer peak demand, again, without Kissimmee in there, is 3 percent lower. We felt we have been a little aggressive in our projections and so we lowered those. And as it turns out, we are going to be very close to what we have actually hit this summer. We removed the 2005 McIntosh 4 opportunity with Lakeland. For a lot of different reasons, we felt that was not wise to proceed, so that was removed. We have added in 2007 a combined cycle at Cane Island or other sites, we do have other options, as well. And then in 2009 we are looking at adding a combustion turbine for peaking purposes.

This slide is not in the main package, but I wanted to speak to it briefly. Undesignated capacity has been an important issue for staff and for the Commission. In this year's ten-year site plan we did identify 25 to 35 megawatts in the near term years that we did not technically have a contract in place for or capacity to build to fill that, but I did want to point out we do have contract options up to 55 megawatts to exercise if we wanted to fill those. So the other important point now with Kissimmee and Lake Worth in the project those numbers disappear. They come in with excess capacity. And that coupled with the contract options, there are no undesignated megawatts at this point.

Just a brief note on conservation and demand-side programs, our cities Leesburg and Ocala have active load management programs. Kissimmee does, as well. And, of course, that will be included in our report for next year. We do have other demand-side active programs in Ocala, primarily, that speak to the residential, commercial, and industrial energy audits and other programs to try to reduce the demand. We are sensitive to the renewable areas and, again, opportunities to have alternate fuels. We do participate in the Utility

Photovoltaic Group. And about a year ago we began burning, along with OUC and Kissimmee, landfill gas at the Stanton plant to supplement the coal there.

There are two cogeneration projects at two customers of our members, Coca-cola and U.S. Sugar, and we do try to use the RFP process to make sure we make good, wise decisions on new future capacity. The last one was the decision for Stanton A, which is under construction, and we are anticipating another RFP to be coming out in a few months to look at options, perhaps at Cane Island so those are utilized.

And just a brief note, again, for the new Commissioners. FMPA's All Requirements Project is one of the four participants in the Florida Municipal Power pool, it is an energy pool with Orlando dispatching that for the four members. We have been operating since 1988. We show the benefits of that energy on an economic basis and we save an average of about $10 million a year in total. That concludes my presentation if there is any questions.

CHAIRMAN JABER: Commissioners, do you have any questions of Mr. Casey? Staff?

MR. HAFF: I just wanted to thank you for this separate sheet on undesignated capacity.

MR. CASEY: Sure. You're welcome.

CHAIRMAN JABER: Thank you, Mr. Casey.

MR. HAFF: Next on the agenda is Gainesville Regional

Utilities.

MR. KAMHOOT: Good morning. My name is Todd Kamhoot, Gainesville Regional Utilities. I would just like to quickly summarize our ten-year site plan for 2002. First, I have a map that shows GRU's service area, its generating plant sites, transmission and major distribution facilities. GRU interconnects with Florida Power Corporation and Florida Power and Light at a total of four separate points. GRU serves the City of Gainesville and the surrounding urban area shown as this gray region on the map, and that includes about three-fourths of the population of Alachua County.

This table summarizes GRU's generating facilities. The Kelly Unit 8 repowering project completed in 2001 added 60 megawatts to the system. There are no retirements or additions planned for the next ten years.

GRU is a summer peaking system, so my discussion will focus on summer resources. GRU has a total of 610 megawatts of summer net generating capacity. Our generation resources include 228 megawatts of coal-fired steam capacity, 106 megawatts of gas-fired steam capacity, 37 megawatts of waste heat steam capacity, 228 megawatts of gas turbine capacity, and 11 megawatts of nuclear capacity. GRU generated 1,959 gigawatt hours during calendar year 2001. 71 percent of the energy was derived from coal, 22 percent from natural gas, 2 percent from oil, and 5 percent from nuclear. This mix of fuel use is not expected to change substantially over the next ten years.

GRU served 81,011 retail electric customers during 2001. A comparison of this year's forecast and the previous two plans is shown. Customer growth is expected to average 1.8 percent per year through the ten-year planning horizon.

GRU's 2001 net energy for load was 1,882 gigawatt hours. This chart compares this year's forecast with the previous two year's plans. Net energy per load is projected to grow at an average annual rate of 1.9 percent over the next ten years. GRU's summer peak demand was 409 megawatts in 2001. To date this year we are at about 433. This chart compares this year's forecast with the two previous year's plans. Peak demand is forecast to grow at an average rate of 2 percent per year. This chart shows installed capacity, available capacity, and summer peak demand with a 15 percent reserve margin added. GRU expects to have adequate reserves without adding any capacity through 2011.

As a supplement or backup document, I attached this table that summarizes the impact of DSM programs on GRU's load and energy requirements and describes the primary types of programs offered by GRU to its customers. Two fairly recent or on-going developments listed in the bottom portion under renewables, GRU is in the process of developing a landfill gas to energy project that we expect to have on line next year, and we have recently developed an interconnection agreement and we have one residential customer connected to our grid.

That concludes my presentation. If there are any questions, I will be glad to answer them now.

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

MR. HAFF: None.

CHAIRMAN JABER: Thank you.

MR. HAFF: Thank you. Next is JEA.

MS. BAKER: Good morning. My name is Mary Guyton Baker, and I am an engineer in the system planning department of JEA. And I would like to briefly review with you JEA's ten-year site plan for the years 2002 through 2011.

As of January 1st, 2002, JEA's existing capacity resources included 2,828 megawatts. This capacity does not include our firm sales. It has already been reduced by firm sales, and it does not include the megawatts we lost with the Enron purchase. It does, however, include our purchases from Southern Company and a 220-megawatt winter capacity purchase from the energy authority.

JEA is a winter peaking utility. Our winter peak forecast for this time period is projected to grow at 3.2 percent. Our energy projection is forecasted at 3.2 percent, also. Our ten-year plan includes in 2002 the winter, a 220-megawatt winter purchase; in the summer of 2002, the return of North Side Unit 2, also in the summer we purchased 75 megawatts to replace the Enron contract that is not available to us anymore. In winter 2003, we have the return of North Side Unit 1 from repowering. In 2004 we have a need to purchase 285 megawatts for that season because two of the Brandy Branch CTs will be taken off-line for conversion to combined cycle the summer of 2004. Also in the summer of 2004 we signed a contract with Biomass Industries for a 70 megawatt purchase from them of a biomass plant. In 2008, the winter of 2008 we project that we will build a 323-megawatt combined cycle unit. 2010, winter of '10, a 250-megawatt solid fuel option. And in the winter of 2011, we will build a CT, a 174-megawatt CT.

MR. HAFF: Before you leave that page, Mary --

MS. BAKER: Yes, sir.

MR. HAFF: -- in 2004, the winter purchase of seasonal capacity, what is the status of attempting to meet that?

MS. BAKER: Generally we wait until the season before. We have already given our needs to the energy authority who purchases all of our seasonal and long-term contracts for us, so they are aware of the need and they are looking. But generally we wait until the season before just to get the best price that we can get.

MR. HAFF: In the past when you have needed to purchase on a seasonal basis like this through the Energy

Authority, has will ever been an instance where you weren't able to get all of your seasonal needs through the Energy Authority?

MS. BAKER: No, there has not been a case like that.

MR. HAFF: Thank you.

MS. BAKER: So with these capacity additions, JEA will meet or exceed a 15 percent reserve margin over the 2003 through 2011 time period. In the winter of 2002, with a 12 percent reserve margin because of the loss of the Enron contract. And that is the end of my presentation. Any questions?

CHAIRMAN JABER: Commissioners, do you have any questions of JEA? Thank you.

MS. BAKER: Thank you.

MR. HAFF: Thank you, Mary. Next is Kissimmee Utility Authority. I guess for the last time, right?

MR. MILLER: My name is Robert Miller, and I am the manager of bulk system planning for the Kissimmee Utility Authority. I did not bring an overhead presentation, so if you will follow with the handout. This will be KUA's last ten-year site plan presentation. As a matter of fact, this presentation is basically moot because we have joined the Florida Municipal Power Agency's All Requirements Project. So our capacity and our demand will be combined with the current FMPA's resources.

Basically, I would just like to point out a few things in our presentation as it relates to one of the questions that Commissioner Jaber asked. And that is on the forecast's first graph. We showed our current projection is higher than our previous projection, and this was primarily due to the adjustment in the population projection that the University of Florida made.

And the other is on the gas price comparison. I just wanted to point out the difference in the forecast. And then on the expansion plan page, I just wanted to point out that we have a current reserve margin of 35 percent, and we have committed resources, we are joint owners of the Stanton A unit that comes on line in October of 2003 shown here at the beginning of 2004. And there is a difference in the ten-year site plan as filed in 2008. We have got some unspecified purchases. But as I said, this will be moot as we will be in the All Requirements Project.

CHAIRMAN JABER: So let me make sure I understand. You don't have unspecified purchases until the year 2008?

MR. MILLER: Yes.

CHAIRMAN JABER: And you expect that that will be zero, obviously, as you enter into contracts?

MR. MILLER: Yes. We have options on a couple of our contracts which we could, but it is moot because we will be in the All Requirements Project. So that concludes my presentation.

CHAIRMAN JABER: Thank you, sir. Any questions for KUA? Staff?

MR. HAFF: None.

CHAIRMAN JABER: Thank you.

MR. MILLER: Thank you very much.

MR. HAFF: Thank you. The next presentation will be from the City of Lakeland. Anyone here from the City of Lakeland?

CHAIRMAN JABER: We are not going to hear from the City of Lakeland. We will skip them until --

MR. HAFF: I have a line of cross examination for them.

CHAIRMAN JABER: That sounds like a personal problem. (Laughter.) Skip them for a few minutes.

MR. HAFF: Okay. OUC, then.

MR. ROLLINS: Hello, I am Myron Rollins. I am with Black and Veatch. We prepared the ten-year site plan for OUC and they asked that I present it for you. In the interest of time, because we are going to have trouble getting some lunch in, I thought maybe we would just focus on the plan itself and talk about it a little bit.

OUC's load growth remains strong. It has grown about 3 percent a year still. They maintain a 15 percent minimum reserve margin, and I wanted to talk about that just a little bit with respect to smaller utilities. When you are a smaller utility and you maintain a minimum reserve margin, when you put a block of capacity in it is not immediately used up in your reserve margin so their average reserve margin often is maybe closer to 20, but that is one issue to think about in reserve margins, minimum reserve margins in 15 versus 20.

A little bit of background. If you remember, OUC entered into an agreement with St. Cloud a few years ago to supply all of their loads for the next 25 years, so OUC's ten-year site plan includes St. Cloud and OUC. Another thing that OUC had done a few years ago was sell their Indian River plant to Reliant and took a purchased power agreement back that expires September 30th of 2003, but has options for an additional four years on it. And to replace that, they entered into an agreement, a joint ownership with Southern Company, FMPA, and Kissimmee Utility Authority to build Stanton A, an approximately 600-megawatt summer megawatt capacity unit at Stanton which is under construction. It seems to be on schedule and within budget. Plus the municipals are protected from an upper cap on any cost on that anyway.

OUC's plan shows various Reliant options to fill their needs, and then has a combustion turbine installed in 2006, a simple cycle combustion turbine installed in 2008. With respect to the 30 megawatts of unspecified purchases in 2003, OUC hires a consulting firm out of Boston to do their load forecasts. Their load forecast timing is such that they get the results for their fiscal year budget process, which the fiscal year begins October 1st for OUC, so the load forecast that was used was pre-9/11. OUC has had a little bit of drop in load. Their growth rate is back, so it looks like they probably won't have any unspecified purchase when they get to 2003 with the new load forecast. And in addition they have several options available to them for that power.

I guess that pretty well concludes things unless there are some questions.

CHAIRMAN JABER: Thank you. Commissioners, do you have any questions of Mr. Rollins? Staff?

MR. HAFF: None. No, thank you.

CHAIRMAN JABER: Thank you for your presentation.

MR. HAFF: Next is the City of Tallahassee.

MR. CLARK: Paul Clark, chief engineer for the City of Tallahassee Electric Operations. I am here to provide you an overview of our 2002 ten-year site plan, sort of an update on the activities since that time. Skip the cover page. In June of this year we completed the initial integrated resource planning study jointly conducted with the city staff and Black and Veatch Consultants.

The results of that initial study support the unit additions that the city has been identifying in the last several years ten-year site plans as well as this year's ten-year site plan in terms of the type and timing of unit additions. Subsequent to that study being published, we held a couple of open house meetings in the community to provide them some information about the planning process, the types of resources that we are expecting to add, and allow them to provide some input into the process.

On July 10th, we took the IRP study results to our city commission, and received approval from them to proceed with issuance of request for proposals and the next subsequent phase of analysis.

Quickly, the city generation system or power supply system is made up of 652 megawatts of generation in our Corn, Hopkins, and Purdom generating stations, 35 megawatts of purchased contracts. We have set a new all-time peak demand record this summer in July. Temperatures in excess of 100 degrees drove our net summer peak demand up to 580 megawatts. We have not had an opportunity yet to do an ex post analysis on that, but we do know that we read 104 degrees at one of our substations. We use 100 degrees as our normal temperature. A customer normalization we haven't attempted yet.

And I am going to have to confess ignorance, I don't know whether that is physical or calendar 2001, 2,556 gigawatt hours of energy used by city customers.

The City of Tallahassee is a summer peaking utility. Our forecast is presented here. Our growth rate is roughly -- in peak demand is roughly 2 percent. Annual energy use projections are also expected to increase at an average rate of about 1.7 or 1.8 percent.

As is the case in any resource planning study, of course, we have to take into consideration the relative prices of the different fuels. I guess this is just as good a time as any to remind the Commission that the City of Tallahassee is prohibited under ordinance, absent a referendum by the citizenry, that we are not allowed to build new coal units in Leon or any adjacent county. Therefore, new generating additions are predominately gas-fired. The means by which we might be able to obtain some additional fuel diversity would have to be through purchases.

The City of Tallahassee maintains a reserve margin of 17 percent. As part of the IRP study we did take a look at the appropriateness of that 17 percent. As we referenced in previous ten-year site plan filings, and I believe this one as well, we were looking at the stipulation that the IOUs made a couple years back to go to 20 percent by 2004, questioning whether or not we might should also move in that direction.

The results of the study is looking at the equivalent reserve margin for the City of Tallahassee to a .1 days per year loss of load probability for our system assisted came out to be 12 percent reserve margin. So the 17 percent seems more than adequate to maintain reliability on our system.

This graph just provides a projection of summer peak demand with and without reserves as compared to only our existing resources. This does not reflect any of the contemplated resource additions. As you can see, as in years past, we have a small need in the summer of 2004. We identified a purchase as a means to satisfy that need in our ten-year site plan filing, and I will provide you an update on our activities in that regard here a little later.

Among the different considerations that we have to take into account in power supply planning are the transmission limits that we are faced with in the region. We maintain adequate transmission to back up our most severe generation contingency, loss of largest unit, both our Purdom 8 and Hopkins 2 units are roughly 250 megawatts apiece. Current capability is only about 275 megawatts under summer peak conditions, so that effectively limits the amount of transmission that is available for long-term firm purchases. Similarly, we have to take into account the transmission system's capability to accommodate any incidental excess power for export into the market.

We have been very active in both the GridFlorida and the SETRANS RTO development activities trying to assure that the City of Tallahassee's interests are represented, and more particularly that we see some resolution to our limited transmission access problem sometime in the future.

The fact that two-thirds of our generating capability is comprised of our two largest units, Hopkins 2 and Purdom 8 is not lost on us. This sort of drives the type of generating additions that we are looking forward to in the middle of this decade. That coupled with the fact that our existing fleet of combustion turbines are reaching the end of their useful life suggests that we need to get new quick start peaking capability added to our system. This brings us some operational flexibility. This also would allow us to possibly offset some of that transmission import capability that we reserved for that contingency situation I have previously mentioned such that we might be able to use that transmission for additional firm purchase opportunities.

The City of Tallahassee's fuel use in 2001 was roughly 90 percent natural gas. We do have the capability to burn residual and distillate fuel oils as alternative fuels on all of our generating units. The reason for the high use of natural gas is driven primarily by price. As I mentioned, there is a city ordinance that prohibits us from construction or ownership in a unit built in Leon or an immediate adjacent county and, therefore, purchases are really currently our only means, absent a referendum to pursue some fuel diversity.

You look puzzled.

CHAIRMAN JABER: The ordinance extends to the adjacent counties, as well?

MR. CLARK: Yes. Immediate adjacent counties. We cannot build or own any portion of a coal unit.

CHAIRMAN JABER: Okay.

MR. CLARK: Some other things that we are keeping tabs on, proposed changes to the Power Plant Siting Act, protection of our tax exempt financing ability, and also increased emphasis on increasing use of renewable resources in satisfying future energy needs. We have contemplated as part of the peaking unit additions that we are looking at in the near term there may be some system benefits that we could realize from the use of distributed generation.

Our system is oriented such that all of our generation is on the south and the west side of the city, and our load is predominately north and east. And it creates some challenges and some opportunities with regards to getting the power from the source to the point of use. We have some voltage support considerations, some loss consideration that we need to take into account in siting new generation. And it has occurred to us that if we were able to locate generation a little closer to the load it would satisfy some of those concerns.

We are still considering the possibility of an alliance option, particularly looking at our later need where we have identified some additional combined cycle capacity towards the end of the decade. We are not quite sure yet whether we are looking at a self-build option or participation with another party in that unit.

With regards to purchases, one update since the filing of the ten-year site plan was that we extended our previous 25-megawatt purchase with Entergy coke trading, it is extended through the year of March 2003. Also in the spring and early summer we have done a, sort of a mini-RFP for proposals for purchases, purchase opportunities both from entities in FRCC and outside. We have been in negotiations with one party for some time, the last month or so, though we have not come to terms yet with regards to satisfying that 14-megawatt need in 2004.

The IRP process, of course, by definition considers conservation demand-side versus power supply alternatives. Though we see that any potential demand-side reductions that we would realize from existing or new programs would not satisfy a large amount of our future needs, therefore, we are looking for supply-side alternatives to predominately provide those needs.

Direct load control was the only program in this analysis that showed up as even marginally cost-effective. The city previously had attempted a load control program in the past and was not successful. We are a little reluctant to pursue one now by virtue of the fact it seems like the trend is away from utility activated load control where basically the utility dictates when the load reductions will take place and the frequency with which they will take place to the new demand response types of programs that are contemplated in the market design that FERC has proposed in the SMD and part and parcel of the RTOs.

As I mentioned, short-term we are looking at some purchase options to cover the small need in 2004 to kind of provide us a bridge to our next generation addition. We are targeting the spring of 2005 to add some quick-start peaking capability to our system. Whether that be single or multiple distributed units is yet to be determined. Beyond that in the 2007/2008 time frame we are looking at some additional combined cycle capacity. And as always, if the transmission system will accommodate it, we are going to be looking for firm purchase opportunities that will provide us some resource and fuel diversity.

As I mentioned, the city commission approved that we proceed with the RFP process. We are contemplating two separate RFPs; one to solicit bids for satisfying our short-term need, and a separate one associated with our longer term need. We are looking towards issuing an RFP for the short-term need this fall, the long-term need probably next year sometime, and expecting four to six months for each of those processes.

With regards to future activities, once we received the bids from our RFP process, we will feed those back into the resource planning study process to attempt to verify those specific type of resource additions, both in magnitude and in type. There is some slight considerations and so forth as a part of that process. We will take those results and recommendations back to our city commission and solicit their approval.

That concludes my presentation.

CHAIRMAN JABER: Thank you. Commissioners, do you have any questions of the City of Tallahassee? Staff?

MR. HAFF: No, none.

MR. CLARK: Thank you.

CHAIRMAN JABER: Thank you.

MR. HAFF: Thank you. We are up to the last planned presentation, I guess, for the day from the utilities, and that is Seminole Electric Cooperative.

MR. ZIMMERMAN: Good afternoon. I'm Garl Zimmerman, manager of generation planning at Seminole Electric Cooperative. And I am going to just focus my remarks on changes that we have made to our planning process since we submitted our ten-year site plan back in April.

We mentioned in our ten-year site plan that we have had a 1 percent expected unserved energy reliability criterion for quite sometime. We have adopted also a minimum 15 percent system peak reserve margin. And as our system has grown, the 15 percent system peak reserve margin has become the driving factor. In a minute I'm going to cover another change or addition to our reliability criteria.

Our generation expansion plan as shown in our ten-year site plan, this slide is a little bit busy, but it was a self-build all CT expansion plan. Since the time that we published this, we have reoptimized our expansion plan, and beginning in 2009 three of those units would become combined cycle, and that will be reflected in our next ten-year site plan. Also, the first CT there has been replaced with a purchased power agreement that we just recently signed. And the next three CTs for the 2006/2007 time frame we currently have proposals in-house for both purchased power agreements and self-build options. We will be making decisions on those options by the end of this year, so our next ten-year site plan will reflect exactly how we are going to fill those needs.

And getting back to planning criteria, in addition to the two criterion mentioned earlier, we have added a third criterion which says we will have full service reserves equivalent to 15 percent of our weather sensitive load. Approximately half of Seminole's load is not subject to weather sensitivity because it is covered by a partial requirements contract.

We serve up to a specified capacity commitment level, then the supplier of partial requirements is responsible for the weather-sensitive component of that load. The other half of it, Seminole is responsible for the weather-sensitive component and so we feel that we need 15 percent reserves over and above the Hardee Unit which is not available to us to serve the weather-sensitive component of that load. Hardee is available to us for generation loss contingencies, but not weather-sensitive contingencies, so this causes our overall system reserves to increase slightly.

This shows kind of a bumpy up and down increase in our reserve margins. This really hasn't been optimized yet. We will smoothe that out. We will attempt to use seasonal purchases to help smooth out the overall expansion plan. We have put this criterion into effect immediately. We are taking to our next board meeting a purchased power agreement for a seasonal purchase for this coming winter of approximately 100 megawatts. So we are instituting this for this upcoming winter. And that concludes my comments.

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

MR. HAFF: Just one. Mr. Zimmerman, there was a discussion I guess at Internal Affairs last year when last year's plans were approved in December. On the discussions between TECO and Seminole on the sharing of Hardee and how each utility calculates it in their own reserve margin, and I just wanted to know if you could tell me if those discussions are still going on.

MR. ZIMMERMAN: Those discussions are continuing. We have exchanged some proposals for modification to the Hardee sharing agreement. There are some difficulties to work out. The current arrangement is beneficial to both utilities and it is difficult to change the terms without causing loss of benefit to one party or the other, but we are continuing to work on that and hope to have something resolved.

CHAIRMAN JABER: How did you count the capacity, though, for purposes of this year's site plan?

MR. ZIMMERMAN: In the individual site plans, both utilities count it. In the aggregate FRCC load and resource plan it is only counted once.

MR. HAFF: Thank you.

CHAIRMAN JABER: Thank you. Any other companies?

MR. HAFF: Did you say 12:30 or 1:30? That's good.

CHAIRMAN JABER: Has Lakeland showed up? Are there any other companies or participants from the audience that would like to address us today?

Staff, what was next on your list?

MR. HAFF: We have some opportunity for public comments on the plans, and we usually set aside some time for anyone who wishes to comment on what they have heard today.

CHAIRMAN JABER: That is a second offer. Anyone else?

MR. HAFF: The only other thing, I wanted to bring up some housekeeping on the review of the plans. We normally bring it to you at Internal Affairs in November. I don't see it changing this year. The statute for ten-year site plans requires our review to be forwarded to DEP by January 1st of the next following year, so we will bring it to you in November.

CHAIRMAN JABER: All right. So the Commission's draft report is on schedule to come to Internal Affairs in the November time frame?

MR. HAFF: Yes. Typically, we'll file it for consideration at the first December Internal Affairs, which is usually the first week of December. And just depending on the Internal Affairs schedule, if there is not one scheduled for that time we will try to bring it to you earlier.

CHAIRMAN JABER: Great. Anything else?

Let me thank the companies who participated today, and let me thank you for the quality not only of the presentations, but of your individual reports. It is always real helpful to us when we compile our ten-year site plan report. So thank you. And this workshop is adjourned.

(The workshop concluded at 12:27 p.m.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Office of Hearing Reporter Services, FPSC Division of Commission Clerk and Administrative Services, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED THIS 27TH DAY OF AUGUST, 2002.

JANE FAUROT, RPR
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FPSC Division of Commission Clerk and
Administrative Services
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