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: 10-YEAR SITE PLAN WORKSHOP

DATE: Wednesday, August 15, 2007

TIME: Commenced at 9:44 a.m.
Concluded at 11:20 a.m.

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

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PARTICIPANTS IN ATTENDANCE:

SARAH ROGERS, representing the Florida Reliability Coordinating Council.

GREG RAMON, representing Tampa Electric Company.

STEVEN SCROGGS, representing Florida Power & Light.

R. ALEXANDER GLENN, ESQUIRE, representing Progress Energy Florida.

KATHERINE FLEMING, ESQUIRE, and TOM BALLINGER, representing the Commission Staff.

P R O C E E D I N G S

CHAIRMAN EDGAR: Good morning. We are going to get started. So I call this workshop to order, and we're going to begin by asking our staff to read the notice. Ms. Fleming.

MS. FLEMING: Good morning. Pursuant to notice issued by the Commission Clerk on July 12th, 2007, this time and place has been set for a Commission workshop in the undocketed review of Ten-Year Site Plans.

CHAIRMAN EDGAR: Thank you. And I'd like to ask Mr. Ballinger of our staff to give us a few overview comments and describe what we are hoping to accomplish today, and a little overview of our agenda as well. Mr. Ballinger.

MR. BALLINGER: Good morning, Commissioners.

As you know, Section 186.801, Florida Statutes, requires that all major generating utilities in Florida submit a Ten-Year Site Plan to the Commission for review. The Commission performs a preliminary study of each plan and takes in comments from state, regional and local planning agencies as part of our review process.

After compiling the pertinent information, we will bring it to the Commission at Internal Affairs and the Commission must make a finding of either suitable or unsuitable for each plan. The Commission workshop today is part of our review process, and a brief agenda has been provided to all parties and is part of your notebook that you have before you.

To begin with, Ms. Sarah Rogers will, who is President and CEO of the Florida Reliability Coordinating Council, will summarize the 2007 Regional Load Resource Plan, which is basically an aggregate of all the utilities in Florida.

Part of her discussion will talk on conservation efforts, new renewable, coal-fired and nuclear generating facilities, and also Ms. Rogers will give a presentation on the FRCC transmission planning process and natural gas deliverability for Florida.

In summary, the FRCC is giving you kind of a state of the state of the electric utility industry in Florida, and that's really the sole purpose, if you will, of this workshop to kind of give you an overview.

Following Ms. Rogers will be Mr. Greg Ramon from TECO, who is the ringleader, if you will, of a task force that the FRCC has put together to look at cost-sharing for joint transmission facilities. He will give you an update. You heard a little bit of one at a previous Internal Affairs, and this is a spillover from last year's Ten-Year Site Plan workshop.

And to wrap up the workshop we have Mr. Steve Scroggs from Florida Power & Light who will give you a brief overview of pending nuclear projects, both uprates and new units, that FPL is planning.

Staff -- to give you a little information, staff will provide a report to the Commission in early December. We'll go to Internal Affairs. Usually we have two choices. So if you have some input and comments you want to do, we can bring it back for a second look before it gets submitted to the DEP.

The real purpose of this whole review in determining suitability or unsuitability is to forward our comments to the DEP that they can use in future site proceedings for power plants. And that's a brief wrap-up of what we're here to do.

CHAIRMAN EDGAR: All right. Thank you, Mr. Ballinger.

There will, of course, be the opportunity, Commissioners, for discussion and for questions, and I'm expecting that our staff may have some questions as well as we move through the presentations. Before we ask Ms. Rogers to kick us off with the first presentation, are there any opening comments or questions for our staff? No?

Okay. Then we'll jump right in to the next part of the agenda. Ms. Rogers, welcome.

MR. BALLINGER: Chairman Edgar, if I might. I'm sorry, Sarah.

CHAIRMAN EDGAR: That's all right. Mr. Ballinger.

MR. BALLINGER: I want to make sure that you got updated presentations from Florida Power & Light that they delivered this morning. They were delivered to all of your offices. I want to make sure they're in your notebooks. I think they are. Okay.

CHAIRMAN EDGAR: Oh, yes.

MR. BALLINGER: Okay.

CHAIRMAN EDGAR: And thank you for checking.

MR. BALLINGER: Thank you.

CHAIRMAN EDGAR: Ms. Rogers.

MS. ROGERS: Good morning, Chairman and Commissioners. Thank you for having us here today.

As Tom mentioned, I'm going to review for you our 2007 load and resource plan, as well as a report on renewables, the coal forecast and the nuclear forecast, the impact of the 20 percent renewables. We have a very brief, high-level analysis of that. We're going to go over the natural gas deliverability analysis and go over some contingencies that we've run and some next steps where we are in that process. Update on the regional planning process and then an update on the Florida central coordinated study that was of much interest at last year's workshop.

(Technical difficulty.)

Thank you for your patience on this.

For those of you who may not be familiar with the FRCC, our purpose is to ensure and enhance the reliability and adequacy of the bulk power system in the State of Florida now and into the future. We are a not-for-profit organization. We own no generation, no transmission, no distribution assets. We consist of 27 members. Our members are investor-owned utilities, cooperatives, municipals, Federal Power Agency, power marketers and independent power producers. Our technical activities are carried out by two committees, our planning committee and our operating committee. And what you'll see here today is the culmination of a lot of work by our planning committee.

So with that, I'll go into the load and forecast. In comparison to 2006, the 2007 forecast has been reduced, and there's two reasons for that. One is the amount of demand-side management that is being forecasted by the utilities. As these programs are implemented, that will reduce the peak demand forecast. And additionally the impact of the 2005 Energy Policy Act, which required more energy efficient appliances, we see an impact of that in the later years as less efficient appliances are replaced with more efficient appliances. So that's the primary driver for the reduction in the demand forecast for the summer.

This is the winter forecast. The explanation is the same there. There is a small impact of less of a robust economic forecast. That has reduced it slightly as well.

When we look at our total available capacity over the next ten years, the blue line there is the existing capacity, red is cumulative additions, green is our nonutility generators, which we lump together both the traditional nonutility generators and the independent power producers. And the white, of course, is the transactions.

One cautionary note on this is that we do have a fair amount of generation in the plan that has yet to be sited. For example, in 2010, about 17 percent of that new generation has yet to be sited. And, of course, as we get into later years, that's to be expected.

Our planned reserve margin, we have a requirement of a 15 percent reserve margin, and then there has been a stipulated agreement between the investor-owned utilities and the Commission to have a 20 percent reserve margin for their systems. And as you can see, we look very good in that area.

Our reserve margin review is to ensure that the 15 percent FRCC standard is met. And as you saw from the previous slides, we exceed 20 percent for all peak periods except for 19 percent in 2008. This is something we really need to keep an eye on because as our reserve margin is comprised more and more of demand-side management instead of generating units, we must ensure that that 15 or 20 percent is adequate.

One way to think about this is the reserve margin also is an insurance for us as generating units go out on maintenance or unexpected long-term outages. So if our reserve margin is comprised solely of demand-side management, that would mean that we would have to invoke that demand-side management throughout the period of the generation outage, and that's something that I don't think our customers or consumers would want to see. So we want to ensure that our reserve margin is comprised not only of demand-side management programs but also of generating assets.

Our conclusion at FRCC is the results of the resource adequacy review indicate that our region is reliable for the next ten years, and we are going to be evaluating the impact of planned coal plants being changed to natural gas or other technologies.

Our load and resource plan fuel mix, as you can see -- and this is what was submitted to us by the utilities in 2007, so this does not have the removal of some of the coal units. But our gas continues to grow to 44 percent in 2016. And as a point of reference, in the United States in general the amount of gas capacity is 19 percent. So we far exceed the rest of the United States in that area.

And in the summer demand it's -- this is megawatt versus megawatt hours. You can see that gas is more than 50 percent from, just from a capacity standpoint in 2016. And so these numbers do include Glades, Taylor, Stanton, Polk and the Seminole Generating Station.

To give you a little history of how gas has continued to grow in the State of Florida, this is an historical perspective of the amount of generation or energy, rather, that has been fueled by natural gas. And if we look at that going forward on Slide 13, you'll see if we remove -- the green line is removing the Taylor and the Glades unit and assuming that those units are replaced by natural gas. Now I'm not going to argue that that's the perfect assumption, but that's the assumption that we made for this slide. And then the red line is the, the removal of the rest of the units with the exception of Polk and Seminole 3, Seminole Generating Station 3.

Conservation, we've got a good story here. Florida really does an excellent job in the area of conservation, and our utilities are continuing to improve those programs and expand those programs. This is in the summertime.

In our renewable resources, there our story probably isn't as good as the rest. In 2007, we've got 1,441 -- there was an error on this, on either this slide or the next slide where there was a typo. But this is supply side, so this would not include residential solar systems at this point in time. But as you can see, the bulk of our renewables is made up of municipal solid waste.

Going forward, there's been announcements of 125 megawatts of biomass, 13 megawatts of landfill gas and 88 megawatts of wood products. And I included Progress Energy's recent announcement in late July for their wood products plant.

On the coal forecast, and this is what was submitted, that's a total of 4,652 megawatts. And of that, 58 percent of that has been cancelled. So we will have to replace that generation with other resources.

On the nuclear forecast there's planned upgrades at Crystal River 3, and then Progress Energy is entertaining the concept of putting a nuclear plant in as well in 2016.

Let's take a look now, if you will, at the 20 percent renewables on the net energy for load by 2016. We project our total load to be 308,000 gigawatt hours. So 20 percent of that is about 62,000 gigawatt hours.

If we were to serve that load from large municipal waste generators or biomass generators, we would need about 85 new plants between now and 2016. Another way to look at it is if we were to try to meet this totally from wind, we would need about 23,000 new windmill plants by 2016. And that would take up, just using sort of some industry average types of numbers where there's about five windmills per mile, that would be about 2,600 square miles of land that would be needed for this.

And then we used a fairly low capacity rate on, on that slide, the 15 percent capacity, and I wanted to give you an idea of why we did that.

This slide comes to us from the Department of Energy and it's an estimate of wind capability. And as you can see, the installations for wind would primarily be along our coastline in Florida to get sufficient capacity.

All right. Changing gears a little bit, I'm going to talk to you now about natural gas deliverability. We have two major sources of gas into the State of Florida.

CHAIRMAN EDGAR: Sarah, can I -- I'm sorry. I need to break in. It's a lot of information and really great information. I thank you for that, and I will thank you again I'm sure.

But before we move on to the next kind of subtopic, I did want to see, Commissioners, certainly the opportunity later, but while these slides are fresh if there are any questions or comments before we move on to the next kind of topic of your presentation.

Commissioner Skop.

COMMISSIONER SKOP: Thank you, Madam Chair.

I had a quick question with respect to the reserve margin review. Currently I guess the target is the 15 percent FRCC standard and we exceed 20 percent.

In your opinion, how do you feel, given Florida's continued growth rate, do you feel those numbers are adequate as they exist today or need to be more closely monitored?

MS. ROGERS: I believe that they are adequate. The thing that I think we need to keep our eye on is the percentage of those reserves that are made up of nongenerating assets.

COMMISSIONER SKOP: Okay.

MS. ROGERS: And right now we look good.

COMMISSIONER SKOP: And as a follow-up to that with respect to reducing peak demand to demand-side management, what would be your opinion with respect to time of use metering to smooth the demand curve to reduce those peaks to avoid cutting into that reserve margin?

MS. ROGERS: I'm actually not that familiar with the success of those plans. That might be better addressed to the utilities. They may have more information on that.

COMMISSIONER SKOP: Thank you.

CHAIRMAN EDGAR: Commissioners, any other comments or questions at this time?

Mr. Ballinger, did you have question?

MR. BALLINGER: If I may.

CHAIRMAN EDGAR: You may.

MR. BALLINGER: Ms. Rogers, on the -- let me go first to the renewable slide you had there where you had the 20 percent. And what I get out of this is that --

CHAIRMAN EDGAR: Tom, can you give us the number?

MR. BALLINGER: I'm sorry.

CHAIRMAN EDGAR: That's all right.

MR. BALLINGER: Slide Number 19.

CHAIRMAN EDGAR: Thank you.

MR. BALLINGER: Sorry.

MS. ROGERS: I'm trying to find it.

MR. BALLINGER: That's it.

MS. ROGERS: Sorry.

MR. BALLINGER: What I get from this is that if we were to try to make a 20 percent renewable percentage by the year 2016, it would be very difficult because, I mean, 85 new 100 megawatt plants is quite an achievement. I think we have about, what, ten maybe in Florida now. So would this kind of indicate that it's going to be difficult and it might need some new technology to meet that, if we set that as a target?

MS. ROGERS: I agree with you. I think that new technology would definitely help in assisting, achieving this goal.

Additionally, it depends on how you define renewables. Some states define renewables to include load management and conservation. That certainly would help us if that was included in the definition. I'm not sure exactly how we're defining the renewables at this stage.

MR. BALLINGER: I understand. Okay. And the other slides, we don't need to go there, but basically we've seen changes in the utilities' plans since they filed them in April: The Glades unit, the Taylor unit has been removed or canceled. We haven't updated the plans and the utilities will go through that process; they're in the process now of developing next year's plans and it's a very fluid process. But can you get from this that because of these changes of recent events and things of that nature that the utilities' only options right now I guess in the interim in the next five, six years maybe is to go to more natural gas generation to meet reliability needs?

MS. ROGERS: That's probably better answered by the utilities themselves. I'm not sure what's been available. I know several utilities have had RFPs out for renewables, and I think that most of those plants are coming in in a later time frame. So I would think that it would be a good assumption that in the early years that the coal would be replaced by gas unless there's some significant renewables that are identified.

MR. BALLINGER: Okay. I agree to try to meet our fuel diversity goals, if you will, that that's what we're looking at now to carry us through to maybe we get to nuclear in the later thing.

Would it be appropriate then to -- or at least to give you a heads up, I guess, of next year to have more of a focus on natural gas deliverability? And I know you're going to get into that in your next section, but I see that as being kind of next year's topic, if you will, of the day because that's kind of where we're structured. Is that a fair assessment, do you think?

MS. ROGERS: I think so. I think what you'll see from the next presentation will provide you with some comfort going forward with natural gas deliverability. I'm revealing the conclusions, but we're very -- the utilities here have planned very well by having a significant number of plants that have backup fuels, and that really makes a big difference when you look at -- our percentage of gas units that are solely reliant upon natural gas and only one pipe is small relative to the overall size. So I think that's the thing that we'll have to keep an eye on going forward. As utilities announce new natural gas plants, a natural question might be about backup fuel or alternate fuel capability.

MR. BALLINGER: Okay. Okay. Thank you. That's all I had.

CHAIRMAN EDGAR: Thank you.

Commissioners, anything else before we move to the next? No? Okay.

MS. ROGERS: As you can see, we do have two pipelines into the state, the Florida Natural Gas and Gulfstream. This slide does depict it correctly. The number of pipes on the Florida Natural Gas is several parallel pipes coming into the state, and they're generally spaced about ten feet apart, but the pipeline coming in from Gulfstream is a single pipe that comes in under the Gulf.

Our pipeline capacity into the FRCC region is 3.5 billion cubic feet per day, and that is fully subscribed. There is no excess. But that does not mean that they can't, the gas companies cannot add compressor stations or additional looping of pipe, which they call it, from an electrical world that would be paralleling. But so we do have, we are fully subscribed today for gas.

And you may ask questions as I go along, if you'd like. I don't mind that.

Our high-level assessment, we worked with a firm to put together a modeling system quite like the electrical modeling system we use to model the generation and the transmission on our, in the FRCC region. Our high-level assessment is that we do have almost 40,000 megawatts of generation that can burn natural gas. Of that, 28.8 thousand megawatts is dual fuel capability, and that's either Number 2 fuel oil or Number 6 fuel oil. There's 1,100 megawatts that have dual pipeline access, meaning that they can be served from either Gulfstream or Florida Gas Transmission. Overall, there's 7,600 megawatts of generation that has no alternative fuel capability or alternative pipe access. So that is somewhat of a vulnerability for us going forward.

And to give you a point of reference, if all of the generation capable of running gas ran gas for a full 24 hours, that would be, they would consume 8.5 billion cubic feet per day, which, as you saw from the previous slide, we're only capable of delivering 3.54 BCF per day. So we are dependent upon our alternates.

CHAIRMAN EDGAR: And I think you have fostered some questions. So Commissioner Carter.

COMMISSIONER CARTER: Thank you very kindly. I'm really impressed with the information you've given us here.

You may have that later on and, if so, I'll just wait until then. But if you're looking at a total capacity with a plus factor based upon what our current capacity is when you get to the 8.5 billion cubic feet a day, are you going to address that on what's been done to deal with that in the coming time frame?

MS. ROGERS: Well, essentially most of our gas plants do not run 24 hours a day. Gas is primarily used in the combined cycle plants, sort of dispatching after the baseload generation and then used for peaking. So this scenario where we would run 24 hours a day totally on gas is not very likely to occur. But I did want to include that to, to demonstrate if we were to be totally reliant on the gas plants, we certainly couldn't supply that today.

COMMISSIONER CARTER: Just a follow-up, Madam Chair.

But based upon in your previous presentation on Page 17 where you noticed that there were, the Taylor Energy Center was canceled, the Glades 1 and 2 were canceled, has there, has there been any thought given to replacing that capacity with gas or --

MS. ROGERS: That question would be best addressed by the utilities themselves.

COMMISSIONER CARTER: Okay.

MS. ROGERS: I would only be speculating.

COMMISSIONER CARTER: Okay. Thank you.

Thank you, Madam Chair.

MS. ROGERS: As I mentioned, we worked with a company to develop a gas flow model to simulate transient gas flow conditions. We were very lucky to get a lot of cooperation from the utilities to give us information that was very market sensitive on how much pressure their turbines needed to run and how much their consumption was, et cetera. So the details of this study will remain confidential at FRCC because of all that market data there. But we did want to give you some good valuable information on that.

The simulation provides a detailed assessment of the gas pipeline contingencies, so we run this model very similarly to what we run our power flow studies where you have sort of a steady state where everyone is consuming, all the plants are consuming and all the pipeline is available. And then you can take contingencies, meaning you can simulate failures of the gas pipeline and then see the results of that and how that would impact the generation. And that's -- I'm going to show you three of those cases, but not on this slide.

We did look at, we actually did sort of a base case study with a maximum natural gas transportation capacity into West Central Florida, which is where the majority of our gas plants are concentrated.

One of the scenarios we looked at was a complete outage to a compressor station or pumping station feeding into the West Central Florida area. We looked at a catastrophic failure or guillotine cut of the pipeline serving the West Central Florida generation area, and then an impact to the transportation capacity to FRCC for a complete outage of a pumping station into Florida. And we did not include a depiction of that for critical infrastructure security reasons, so if you can just sort of imagine in your mind these.

In the base case analysis what we, what we found is the available capacity into the West Central Florida area is 1.66 BCF per day. Of that, we have firm contractual rights for generation usage of 1.44. So that means that .22 is being used for other reasons.

We have 14,800 megawatts of gas generation in that region. Of that, we've got 10.8 thousand megawatts of generation that has alternate fuel capability. Our minimum consumption of natural gas is .058 per day or 4,000 megawatts. And in a steady state capacity there's sufficient gas deliverability into that region today with no outages, which should not be a surprise. That's what we would expect.

In analysis number two, as a reminder, this was the loss of a pumping station or compression station that essentially helps push the gas through the pipeline. If we look at that outage, that would reduce us down to 1.45 BCF per day of the 1.66, and then it would reach a new equillibrium point and about 775 megawatts of gas-fired generation would be impacted. So that would mean that we would need to switch 775 megawatts from gas to fuel oil, which would be equivalent to approximately 23,000 barrels a day to replace that. So in this scenario we're all right if we lose a compression station; however, we will be burning fuel oil as opposed to natural gas.

In analysis number two, we looked at a guillotine break of the gas pipeline and what the impact to generation would be. This is a -- this analysis is really dependent upon time of day impacts. Impacts could be delayed up to three hours, but approximately 2,900 megawatts of gas-fired generation would be impacted. And, again, we do have enough generation that can run on alternate fuel to protect us from this situation.

And the last analysis we looked at was a complete outage of a pumping station into the State of Florida, so closer to the Panhandle, impacting the FG,the Florida Gas Transmission supply. Again, this is time dependent on day, on the time of day. But approximately 900 megawatts of gas-fired generation would be impacted, which is less than 2 percent. So, again, we do have enough generation that has dual fuel capability to cover us in this situation.

So we do have redundancies to mitigate natural gas outages: The dual fuel capability, the dual pipeline, supply alternatives and possibly if the utilities pursue a liquid natural gas project.

Our next steps are to reassemble our Gas Study Group and share with them these results. You're getting a preview before the study group has. And to review the summary reference document, the results of the analysis, increase the understanding of the current pipeline operations, refine the modeling parameters as things have changed. We also want to look at the amount of gas storage that has been procured by the utilities and see how that impacts us from a supply standpoint, and there's been a lot of positive progress made in that area. And we also -- and we'll continue to do that. So those are our sort of next steps there.

And that's all I have on natural gas deliverability, so if you have any questions.

CHAIRMAN EDGAR: Commissioners, any questions at this point? No? Mr. Ballinger, no questions from staff?

Okay. We're ready to move on.

MS. ROGERS: All right. Now I'm going to cover with you the FRCC regional planning process. For some of you this will be somewhat of a review. There have been some minor changes in it. For some of you it may be new to you.

The planning committee promotes the reliability of the bulk power system in the FRCC region. We assess and encourage generation and transmission adequacy. We provide a vehicle for ensuring that the transmission planning within FRCC will provide for the development of a robust transmission network within our region. We have three working groups that also assist that: We have the transmission working group that develops the long-term plans, we have a stability working plant that assesses the stability of the bulk power system by doing contingency and sensitivity analyses, and a reliability working group that performs reliability assessments of the resource adequacy or the generation side for the future ten years.

In July of 2005 the FRCC board of directors approved our transmission planning process. It started with transmission owners' plans and sought comments from stakeholders. The transmission working group and the staff, the FRCC staff reviewed these plans to ensure the robust reliable system. Members include FERC jurisdictional and nonjurisdictional entities. And we provide Ten-Year Site Plans and reports to the Florida Public Service Commission.

We have revised the planning process to support FERC Order 890 objectives. These revisions have been approved by the FRCC planning committee and by the FRCC board of directors.

In our planning process we compile a database of all the data from our members, so it's a very dynamic database. As changes are made, we update that database. So, for example, as the utilities identify replacement sources for their coal generation that has been cancelled, our database will be updated, we'll do an analysis of that, we'll make sure that the planned transmission associated with that will support that new generation, always looking to ensure for reliability and robustness.

Our first step in our planning process is the transmission owners submit their plans that they've done sort of for their footprint to the FRCC, and those plans are posted for comments from stakeholders.

We collect the feedback from our customers and other stakeholders. We review and assess the plans to ensure that the composite plans meet the customer's need and ensures reliability. And then we conduct sensitivity analysis to ensure that under most predictable circumstances that these plans will continue to work. And when we run studies, we run everything at peak periods. So we run sort of worst-case analysis from the beginning. And then when we do the sensitivity analyses, we're sort of making that worst-case even worse. And this supports the FERC 890 requirements to have coordination, openness and transparency in the regional planning process, and supports comparability and information exchange principles in the Order 890.

We issue a preliminary regional plan, then the transmission planning group approves the regional plan. And we also have a dispute resolution process for unresolved issues.

If there are any disputes, we do have a process to address those.

Some of the key aspects of our planning process is it does provide coordination amongst all the participants, it provide openness and transparency. People have an opportunity to have input into the plans. We coordinate the information exchange and we ensure that there is comparability throughout the process.

I mentioned we have the dispute resolution process. Regional participation is also ensured. We coordinate with participation from the entire region. We do inter-regional studies with SERC, which is the FRCC equivalent to our north and west of the Apalachicola River. We do economic planning studies, and we also are including a cost allocation agreement, which Greg Ramon will be covering in a little bit where we stand on that.

Our latest version of the transmission planning process will be approved by our board of directors later this year, which will include the cost allocation.

In summary, our planning process does meet all the objectives outlined in FERC Order 890 for regional transmission activities. It's consistent with all nine principles outlined in the order. It's supported by our transmission owners, customers and stakeholders, and, most importantly, it has continued to be supported by our Public Service Commission.

We do three studies a year. The Ten-Year Transmission Reliability Study, we do summer and winter assessments for the upcoming summer, upcoming winter. We're working on the 2008 winter right now. And we do inter-regional transmission studies to ensure that our system is compatible with our neighboring systems.

Our Reliability Standards Test, we look for single component outages with no loss of electrical demand. So that means at the peak period with all the generation dispatched we can withstand the loss of a generator or a transmission line or a transformer and still serve all of the load in our region.

We also look at multiple component outages. And in those cases we look -- the standards require us to have a controlled loss of electrical demand or no loss of electrical demand. So we can withstand at the peak period the loss of two components and not have a cascading effect like they had in the northeast in August of 2003.

And then extreme component outages, again, we looked for no wide area cascading outages. So we want to ensure what happened in the northeast does not happen here in Florida. And our analysis of the transmission plans for 2007 through 2016 do satisfy these tests.

I mentioned we do an inter-regional transmission study. The purpose there is to determine the amount of reliable import and export capability into the FRCC Southern

Company transmission interface. And we completed that study, and for the summer of 2007 we continue to have 3,600 megawatts import capability in the summer and 1,500 megawatts export capability, and then for the winter we'll have 37 import and 2,000 export. These numbers haven't changed much over the recent years.

And that's what I have for you on the planning process, and if you have any questions.

CHAIRMAN EDGAR: Commissioners, questions? No? Staff, questions? No? No questions.

You're giving us all the answers.

MS. ROGERS: Well, good.

Now I'd like to update you on one of the products of our planning process, and that's the Florida Central Coordinated Study. As you -- those of you who were here last year, we got a lot of interesting information on that.

We have updated the study to include the years 2014 through 2016, and we do not see any problems in those years. And this is an update on the schedule of the lines that were committed to by the utilities, and it's a very good story. We've got several projects that have been moved up; one project that was delayed because of the moving up of another project and we had some dates swap. I'm not sure whether that was our error in that or a change in priorities. But overall this is good news. They're making a lot of progress on the, on building these lines. The Lake Agnes/Gifford line is a TLSA line, and Progress Energy and TECO have applied for the needs application. So everything is moving along very smoothly in this area.

And that's all I have on the coordinated study. Any questions?

CHAIRMAN EDGAR: Sarah, you had -- and this may be a question that's better posed to Mr. Ramon, and, if so, that's fine. But you had mentioned a few slides back about the cost allocation plan that would be approved by or put to a committee here in a couple of months. Cost allocation is an issue that has come to us occasionally, not often actually but occasionally. Could you elaborate just a little bit on some of the issues that go into that, the cost allocation and how that process works for the FRCC?

MS. ROGERS: Well, actually that's what Greg is just going to cover next.

CHAIRMAN EDGAR: Okay.

MS. ROGERS: But that completes my presentation. So if you have any other questions for me, I'd be happy to entertain those.

CHAIRMAN EDGAR: Okay. Questions, Commissioners, on any of the other points?

Okay. I have one also. Towards the, and there's no reason -- oops, excuse me -- no reason to go to the slide, but one of the earlier slides at the beginning you had mentioned, or a couple of them mentioned to us that in a number of the out years that some of the units in, that are being considered for reliability and robustness purposes are not yet sited, and, of course, that makes sense. Then you also discussed a process or the need and the ongoing review and evaluation of possibly replacing planned coal units that will not go into effect. And then I'm also wondering with, with -- let me try again because I realize I'm wandering.

Realizing that siting is always difficult, and probably even becoming more so just due to growth and environmental issues and other related factors, how does that evaluation process work in the out years to assure that robustness and reliability and 20 percent reserve margin when, indeed, some of the units being considered are not sited and could potentially run into permitting problems?

MS. ROGERS: That's an excellent question. We, what we look at is an assumption of where they're going to be located regionally. The out years are much less reliable because so many things change, as we've seen over the years. The plans change, the load forecasts change, et cetera. But we do, what we do look at is will there be enough generation to match the load? And we don't really address the will there be the transmission there, et cetera. We address that as it becomes closer in the time frame. Would you agree with that?

CHAIRMAN EDGAR: Commissioners, any questions for Ms. Rogers before we move on to the next presentation? No. Okay. Seeing none. Sarah, thank you so much. Excellent, excellent presentation.

MS. ROGERS: Thank you. I appreciate your time.

CHAIRMAN EDGAR: And next on our agenda we have Mr. Ramon with TECO. Good morning.

MR. RAMON: Good morning, Chairman Edgar, Commissioners. I am the ringleader of the Florida Cost Sharing Task Force. Knowing my colleagues, I'll never be able to shed that title. So thank you, Tom.

This morning I'm going to provide you -- if I can get the slide to -- how do you get it up?

(Technical difficulty.)

MR. RAMON: There you go. Technical difficulties aside, this is a work in progress. And today I want to provide you a status of where we're at, a time line. But along with that, I also want to provide you a better understanding of the, in the FRCC region of the issues that we're trying to use the cost allocation methodology to resolve.

(Technical difficulty.)

All right. Okay. I want to spend a minute, if I can, on this slide to give you some context for the FRCC effort on the cost allocation because it's important to know that there are two regulatory initiatives that are driving us on cost allocation. It's the initiative before this Commission which we reported on a bit last year and the one at FERC, Order 890, and I want to share a little bit about those two initiatives.

The development of a cost allocation methodology for this region is an outgrowth of needed enhancements to the FRCC transmission planning process that Sarah just talked to you about. In the Commission order in the closing of the "Good Florida" docket, to quote from the Commission's order, "Florida would still benefit from laying additional basic framework for wholesale competition and efficiencies that may be gained by making modifications to the current market structure." And you identified at least two initiatives there, and that was the transmission planning process and the development of a cost-based spot market. And as you recall, back in June we were at your Internal Affairs meeting to report on how that's moving along rather well. So cost allocation as a part of the transmission planning process was identified early on, and Sarah mentioned this task force was created.

Regarding last year, as you all know, the Central Florida study underscored the need in the region to have a methodology to address third-party impacts, which I'm going to define that term a little bit better for you in a moment.

But lastly, the other regulatory initiative is FERC Order 890, which is the reform of the Open Access Transmission

Tariff. That added further impetus to developing the cost allocation methodology. Just quickly, the OATT, the acronym for Open Access Transmission Tariff, was a landmark ruling back in '96 aimed at fostering competition in wholesale power markets by standardizing the provisions for transmission service.

This reform is very broad in scope and covers many facets of the provision of transmission service which I won't cover except for transmission planning. In their order, FERC is requiring each public utility transmission provider to submit a proposal for a coordinated and regional planning process that complies with the planning principles and other requirements in the final rule. They enunciated nine principles, which I won't go over in detail, from coordination, openness, transparency, some of what Sarah talked to you about before, but the ninth principle is cost allocation.

Fortunately, FERC doesn't prescribe any specific cost allocation methodology and they do allow regional flexibility. But when they review and approve the cost allocation that we're going to, transmission providers will have to have in their tariff, they will weigh three factors.

Real briefly, the one factor would be does the proposal fairly assigned costs among participants who cause incurrence of cost and to those who benefit from them? And another factor would be does the proposal provide adequate incentives to construct new transmission? And lastly, but importantly, whether the proposal is generally supported by state authorities and participants across the region.

So with that background, let, let's talk about the conceptual framework of where we're at at this point. What the cost allocation methodology in the FRCC region is about is so-called third-party impacts. A real simple definition of that would be transmission expansion that's required on one system due to additions; an example being generation on another transmission system.

We have a very integrated network in Florida, and it's important that however the electrons flow, that a transmission owner is responsible for upgrading their respective systems to meet all the various planning standards. But because of the third-party impacts, we need, we need to and we are developing a cost allocation methodology to address those impacts.

So let's make sure we're all on the same page what we mean by third-party impacts with this very simple example. And I'm going to give credit to the task force. There's a lot of illustrative examples that are being developed for clarification purposes, and this is just one of the many examples.

So we have for purposes of the example two utilities here. We have Alpha, which is the white portion of the slide, and Bravo, the other utility, which is a rectangle with dots. Alpha is interconnecting a generator at Point B, the red circle, and the line from Note A to the city across the Bravo system overloads. And the fix for that is to rebuild Line A to the city. So the situation here is Alpha is installing the generator and has a request to Bravo to be able to fix that. And Bravo definitely has the overload and the remedy. So this is a third-party impact for which this cost-sharing proposal will apply. Now this is a very simple example. It gets quite complicated in an interconnected network to identify all the generators that would have to contribute to the cautionary and that type of thing.

Let's drill down just a little bit. This is still very high level. Two parts here. We are developing threshold criteria to determine whether the request by an affected transmission owner, Bravo is the affected transmission owner in the simple example, is qualified for this cautionary proposal. And some of the criteria that we're working on is a prespecified change in flow on the affected transmission owner facility which results in a reliability standards violation. We're saying that the transmission expansion must be 230kV or above and the costs associated with the transmission expansion must exceed a prespecified amount. And lastly, but importantly, the transmission owner must identify itself with a potential affected transmission owner in a very timely manner.

The next part, who pays and how much, as you would well imagine is quite an area of discussion. But we do have a framework, believe it or not, that we're working on in which a portion of the load in an area or zone associated with the deed for the transmission expansion would contribute to the cost of building the new facilities on the Bravo system in that example, any portion to the sources or cluster of sources which are causing the need for the transmission. And we have a lot of work on that and a lot of clarification going on, but that at a high level is the framework.

Lastly, we have a very, very aggressive schedule driven largely by the FERC Order 890. By December 7th of this year -- by the way, it used to be October 11th and there was an extension. It would have been nice if we had had more time. But December 7th is the date, and transmission providers must file a compliant filing with the FERC by that date. So backing up from that stake in the ground, this Friday the FRCC board will review the detailed framework that I've presented to you at a very, very high level.

And as a part of the FERC process to develop the transmission planning process, remember, there's nine principles, not just cost allocation, but September 14th of this year the transmission providers, and there are what we call sponsors of the transmission planning requirements that have worked on a single document, and that's Tampa Electric, Florida Power & Light, Progress, JEA and Orlando, we will file on our OASIS sites on September 14th the latest strawman document that includes cost allocation but also the other principles and how we are going to meet those requirements. And we have a stakeholder process providing input into that document that we will post September the 14th.

October and November, FERC is conducting a second round of technical conferences to review the planning processes. Our work will be quite heated and quite a lot of work to be done between September through November to develop further additional detail and clarification on this cost allocation methodology and principles, final board approval, and last, but not least, review and approval by this body. We're -- staff is following this work and I'm in conversation with staff to design the regulatory review process for this cost allocation method.

And then last, but not least, December 7th -- I wonder if that's a Friday, Day of Infamy -- we have to make our compliance filing. So it's a work in progress. I'm sorry I don't have the solution for you, but that's, that's where we are.

CHAIRMAN EDGAR: You mentioned some of the principles that were being used to, at a very high level conceptually to try to meet the goals and requirements. Could you run through those again?

MR. RAMON: This is -- the principles of the FERC?

CHAIRMAN EDGAR: Uh-huh.

MR. RAMON: Okay. Coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, and economic planning studies and, lastly, cost allocation.

CHAIRMAN EDGAR: All laudable goals.

Commissioners, any questions for Mr. Ramon? Staff? No?

All right. Thank you.

MR. RAMON: Thank you.

CHAIRMAN EDGAR: And next we have Mr. Steve Scroggs with Florida Power & Light.

MR. SCROGGS: Good morning.

CHAIRMAN EDGAR: Good morning.

MR. SCROGGS: Thank you, Chairman Edgar and Commissioners. We're glad to have this opportunity to share FPL's plans for pursuing future nuclear generation in the State of Florida.

Just to let you know, I'm sure you know nuclear generation is a proven technology, a reliable generation technology that we've used to provide approximately 20 percent of the energy needs today. That's down from 30 percent in the mid '70s. The need for emission-free sources of electrical generation combined with the desire for greater fuel diversity and energy independence has created an opportunity for nuclear generation to reemerge as a credible alternative to supply our customers' needs.

FPL, as a leading provider of nuclear generation both in the state and nationally, is responding to these challenges of meeting our customers' needs by two initiatives that I look forward to sharing with you today. In general we see both initiatives as supportive of Florida's goals overall. Nuclear generation provides a real means to help substantially meet these goals.

The primary goal articulated by Governor Crist's Executive Order 07-127 is to achieve meaningful greenhouse gas reductions. Nuclear generation is the only baseload generation technology that produces no emissions, neither greenhouse gas emissions or other pollutants such as mercury or sulfur dioxide.

The incorporation of new nuclear baseload generation into the FPL portfolio reduces greenhouse gas emissions in two ways. First, by new nuclear capacity being placed online, we're avoiding the need for fossil-based generation that does emit gas. Secondly, as new nuclear generation comes on to the system as baseload generation, existing older fossil generation moves into an intermediate or peaking role, which reduces the capacity factor, again reducing the amount of generation that fossil generation provides.

By its nature, nuclear generation can play an important role in increasing energy independence and supply reliability into the state. Earlier, Ms. Rogers gave us a good summary of the gas infrastructure into the state. As it affects FPL, approximately 50 percent of our energy needs are met using gas-fired generation today. We have a considerable amount of dual oil or gas fuel capability on our system, and that was put to the test in the summers of 2004 and 2005 when we received a number of hurricanes that disrupted supply in the Gulf of Mexico requiring us to maintain system reliability through the use of a combination of alternative fuels for our gas-fired generation and the oil, coal and nuclear generation that exists on the system today. Increasing the contribution of nuclear in the portfolio provided direct means of increasing reliability and energy independence to the state.

Additionally, we feel that these benefits can be accomplished in concert with and not at the expense of enhancing the contributions of renewable resources, conservation and other demand-side management programs. Over the next ten years we project a need of over 6,000 megawatts of new capacity to be required. Nuclear can supply some of this generation but not all.

Contributions from renewable resources, conservation programs, demand-side management programs will be just as important to meeting the needs of FPL's customers in an environmentally responsible way.

Just a little more detail in terms of -- I've talked about baseload, intermediate and peaking capacity. FPL's capacity demand shape has two components: A baseload component, which is demand that is required for most of the hours or if not all of the hours of the day. And the second component is a variable component. It peaks in the late afternoon with the minimum occurring early in the mornings.

FPL's baseload plants are used to serve the baseload portion of the daily demand curve. Intermediate and peaking units are brought on as needed during the day to serve the variable portion. Non-emitting renewable generation technologies like sun and wind can provide energy when the resource is available. FPL would use all available renewable generation to replace fossil fuel baseload, intermediate or peaking generation resources, while nuclear generation would remain online serving baseload needs without emissions throughout the day.

Now I'll go through the specifics of our plan. We're looking at two different initiatives. The first relates to providing uprate or power capacity additions to our existing facilities. The second would be introducing new nuclear, a program to pursue new nuclear on the system.

The industry has been very adapted in the past years to increase additional capacity at existing facilities. In fact, over 4,000 megawatts of additional capacity has been approved by the NRC at existing facilities in the last 20 years.

FPL has conducted uprates in the past. In 1981 and 1986 we conducted uprates at the St. Lucie facility and in 1996 at the Turkey Point facility. The process is proven, efficient, and it leverages the existing investments for the benefit of customers, and we believe additional uprates at our existing facilities will serve customers well.

As previously announced, FPL is also pursuing two options, two new nuclear plants at Turkey Point as an option. These units would be among the first new nuclear generation units designed, licensed and constructed in the United States in over 30 years.

Specifically to the schedule for the power uprate, we're looking at the first step obviously being the need determination process with the Commission. FPL would follow that by pursuing the necessary licensing approvals at the state and federal levels. We would pursue state and federal licensing in parallel.

In concert with that in order to maintain the aggressive schedule that we've set for the uprates we would need to begin the engineering and design work necessary to support the upgrades.

The plan for implementing the upgrades involves utilizing the current maintenance schedule for refueling and coordinating the upgrades to be accomplished during these already scheduled outages. The outage time periods will be extended a bit longer than they would otherwise, but it's a nice fit within an already scheduled maintenance outage.

The option for new nuclear is something that we have been exploring for a couple of years and we have been taking action on. We see now that the action is needed to preserve this option. We need to take concrete steps now to investigate the ability to license and construct new nuclear in Florida.

The NRC and state licensing processes are the next step in this investigation following the need determination and would provide the appropriate means to develop the information needed to guide future decisions. In order to obtain the earliest possible operation of new nuclear decisions regarding preliminary expenditures will be required. Postponing decisions on preliminary expenditures could result in disproportionate delays to the project as supply sources tighten with the increase in the number of announced new nuclear projects in the United States and internationally.

New nuclear generation no doubt will present many challenges for us as the construction and licensing process emerges from about 30 years as a hiatus. These challenges are not insurmountable, but they will require a consistent disciplined approach to resolve uncertainties and to develop the true potential of new nuclear generation.

Specifically as to schedule in the near term, the process to deploy new nuclear generation will certainly be much longer than the uprate process. Following the need determination, the state and federal license applications would be developed. The application development process itself will take between 15 and 18 months, and then there's a review process at both the state and federal levels. These applications are extremely detailed and will review all technical, geological, environmental and socioeconomic issues from a number of perspectives. The application review process offers a significant opportunity for involvement of the public and their representatives in local, state and federal oversight positions.

As the applications are prepared and reviewed, FPL will have the option of making these incremental investments I had talked about earlier that will help keep the timing of the units on track. In order for these units to be available by the end of this next decade, design and site preparation activities will be required prior to the expected receipt of the licenses. FPL will communicate the timing and the need for these incremental investments to the Commission via the nuclear power plant cost recovery filing process.

In terms of the two major decisions to embark on a nuclear project, there's a site selection and a design selection process. FPL has conducted two important studies in the past year to address the selection of these two important areas. A site alternative study was conducted that reviewed over 20 candidate sites, ranking each site against a number of criteria specific to nuclear site suitability. This process identified Turkey Point above others as a very well-qualified site for additional nuclear capacity.

FPL has also been reviewing five nuclear designs as candidates for implementation. An engineering review was conducted that determined that all five designs are technically viable and would be technically capable of providing good, safe, reliable generation. The choice of design, therefore, will be based on a balance of cost and risk management features that will be offered by the vendors. We expect to complete the design selection process early next year.

Coordination is the hallmark throughout this upcoming process. We cannot succeed without the support of the Commission and without the support of government at local, state and federal levels. Coordinating the concurrent reviews of the needed applications at the state and federal level will be a significant challenge and will require the good faith efforts of many just to manage the total volume of information that's contained in both of those applications. FPL's customers are relying on us to execute these steps in a timely fashion and to deliver the benefits of new nuclear as soon as possible.

Certainly financing these initiatives will be a challenge. A stable regulatory environment with continued support is necessary to maintain cost to customers as low as possible.

That's my prepared remarks. If I have any questions, I'd be happy to answer them.

CHAIRMAN EDGAR: Thank you. If I could just make one comment first.

As I was coming in to work this morning I was listening to NPR, as I do most mornings, and there was a story, many of you probably heard it as well, a story about the resurgence of support for nuclear generation across the country, and that was the way the reporter characterized it. So very timely discussions that we are all having obviously.

And on that point you had, I think you mentioned in your presentation that the proposed potential new units at Turkey Point would be the first new nuclear generating units in the country. And so I guess my question was realizing that there is interest by other entities and there are other, and other states as well looking at potential new nuclear generation, is this potential project by FPL that far ahead of some of those others so that it, right now it's scheduled to be the first?

MR. SCROGGS: No. No. I'm sorry if I implied that.

CHAIRMAN EDGAR: I may have misheard.

MR. SCROGGS: It's in the first wave of new projects.

CHAIRMAN EDGAR: First wave.

MR. SCROGGS: There are approximately seven applications for the combined construction operating license that will be submitted by year's end 2007. There will be another five to seven submitted next year. And then FPL is looking to be in early 2009 to provide its application. So we're not in the vanguard but we're in the first wave.

CHAIRMAN EDGAR: First wave. Thank you.

Commissioner Argenziano.

COMMISSIONER ARGENZIANO: Thank you. And thank you for the presentation.

So what FPL anticipates is for the plant, if all goes well and on time, the first plant to be built at the Turkey Point plant site, I guess, in 2018 built?

MR. SCROGGS: 2018 is our target date for the first unit to be commercial. Yes, ma'am.

COMMISSIONER ARGENZIANO: Okay. And then the second is 2020 at the same site?

MR. SCROGGS: Again, that's our target date. Yes, ma'am.

COMMISSIONER ARGENZIANO: Okay. And that is if, of course, everything goes accordingly.

MR. SCROGGS: Correct.

COMMISSIONER ARGENZIANO: Okay. Thank you.

MR. SCROGGS: Again, we look at this as, as an option that we need to explore. There's a certain, certainly a significant amount of uncertainty that we are cognizant of. I think the state legislation that has inspired the rule changes has recognized that, and that's the process that we've agreed to move forward on.

CHAIRMAN EDGAR: Commissioner Skop.

COMMISSIONER SKOP: Thank you, Madam Chair.

Thank you for the presentation today. I think it's very, very informative.

With respect to the -- I think the uprates or the potential uprates speak for themselves, and I think that's good because it leverages existing nuclear generation capacity furthering on what already exists.

With respect to the two nuclear units proposed for Turkey Point and the targeted in-service dates of 2018 and 2020, is there any thought that's been given or ability to leverage accelerating those by any degree? I know that the permitting process and the long lead materials are certainly important, but is there any margin in the schedule to perhaps, if things go well, to have them come in service on an earlier date?

MR. SCROGGS: At this stage it would be very difficult for us to project how much margin is in the schedule.

But we know and recognize that there are opportunities that will become available as the early process of applications that go into the NRC this year and next start to wind their way through the review process. That will give us a lot of feedback on what is expected in terms of timing and content of the application review and will give us the best opportunity to put forth an application that will have the minimum amount of review necessary. So we think that in this position there's a number of opportunities for us to learn.

Again, the key to an earlier and accelerated commercial operation date is some of the early steps and expenditures that we would need to take to facilitate the construction schedule. Particularly there's some large, heavy forgings that are needed at the beginning of construction. So you actually have to manufacture and purchase those, have those shipped to site a year or two in advance of actually starting construction. So if you want to, if you want to make the most accelerated schedule, you would make investments early to facilitate that enhanced construction schedule.

COMMISSIONER SKOP: And a quick follow-up to a point you just made with respect to the existing technology base. You know, the pipeline is pretty small because the last time I checked we don't have a lot of nuclear procurement options. But would it be better to, as you mentioned, to put those firm orders in place earlier rather than later to the extent that the pipeline would be -- similar to wind turbines now, you can't get a turbine for a couple of years because the pipeline is so already backed up, if you will. Is there some benefit to, to doing that, to making those orders to get your order locked in for those forgings and such?

MR. SCROGGS: Yes. And back on Slide 12 I think you'll see we've identified that some of those long lead procurement activities could actually start next year.

COMMISSIONER SKOP: Okay. And then just two more quick follow-up questions.

With respect to the nuclear designs under review, are those all pressurized water reactors?

MR. SCROGGS: No. There are two designs that are boiling water reactors. GE has an ABWR, advanced boiling water reactor, that's actually been under construction in Japan and Taiwan. Then they also have a larger unit, an economic simplified boiling water reactor. Those are both BWR technologies. The other three designs are pressurized water reactors.

COMMISSIONER SKOP: Okay. And just -- I don't want to hold you too much to the carpet on this because it's early in the stage, but FPL's existing generation is all pressurized water reactor; is that correct?

MR. SCROGGS: In the State of Florida it's pressurized water reactors.

COMMISSIONER SKOP: Right.

MR. SCROGGS: But we do have boiling water reactors in our FPL energy fleets, particularly Duane Arnold.

COMMISSIONER SKOP: And with respect to your service experience, like in, I think, the technology, how do you just generally trade off between those two, having the existing experience with pressurized water versus the boiling water?

MR. SCROGGS: In reality, our operational folks are comfortable with either technology. We think both provide very safe, reliable designs that have been proven. There are, you know, other minor differences that are more operationally related, but either design technology would be satisfactory to us.

COMMISSIONER SKOP: Okay. And finally, is FPL -- you know, I commend the collocation on the existing footprint, which I think is a very, very good opportunity for expanding.

Is there, given the need for additional nuclear generation within the state, any consideration to considering other sites that would allow additional expansion in the future for nuclear plants?

MR. SCROGGS: Let me -- we are looking at other opportunities for nuclear generation siting in the United -- in the State of Florida and within FPL's territory.

COMMISSIONER SKOP: Okay. Thank you.

CHAIRMAN EDGAR: Commissioner McMurrian.

COMMISSIONER McMURRIAN: Thank you. And thank you for your presentation.

Just a follow-up on some of Commissioner Skop's questions about the design options. Are all of those design options, all five that you're looking at, are all those preapproved by NRC?

MR. SCROGGS: No. They're in various stages of approval.

The ABWR, which is GE's 1,350 megawatt reactor, is a design that has been certified. The Westinghouse AP1000 reactor, which is 1,100 megawatts per unit, is also design certified. General Electric has submitted their design certification application for the larger ESBWR. It's under consideration at the Nuclear Regulatory Commission right now. And then there are two other larger pressurized water reactor designs: One by Mitsubishi Heavy Industries and the other by Areva, a French company, that are both in the process of filing their design certification documents to the NRC now.

COMMISSIONER McMURRIAN: Okay. I have several questions, Chairman. Thank you.

On that point, at some point whenever I was on a trip to, for meetings on the Nuclear Waste Strategy Coalition, an NRC representative made us aware of concerns that they had about staffing. Apparently they have a lot of -- a lot of their senior staff members, they're at the stage where they have a lot of retiring staff members and things and they identified that as being a concern. Do you have any information if they've addressed those concerns? I realize they'll probably get a lot of applications for new nuclear coming in, perhaps uprate projects and things like that, that's going to really put a, add to their workload significantly. Have you heard any --

MR. SCROGGS: Absolutely. We are aware and we have, of course, close, regular communication with the NRC. As you may be aware, they have opened a new division, Office of New Reactors. It's based out of Atlanta, and it's solely to focus on the new reactor licensing efforts in the United States. They're staffing up, they're budgeted, they feel that they're very ready to go. In fact, some of the more recent discussions have been very optimistic that time lines that had been discussed three years ago might be able to be accelerated.

And, again, one of the keys to that is a standardization of design so that the third unit of a given design that the NRC reviews looks very much like the first unit with the exception of site-specific items that can't be the same.

COMMISSIONER McMURRIAN: Thank you. Also, given your proposed time line, do you think your company will qualify for the federal tax credits that are available?

MR. SCROGGS: At this point our time line would not support us qualifying because we would target to file our combined operating license application in 2009, which would be beyond the December 2008 time line.

COMMISSIONER McMURRIAN: I guess along those lines, do you think -- does FPL project that there's going to be continued support at the federal level for new nuclear?

MR. SCROGGS: We feel that there is a signal from the state and federal legislature of strong continued support for new nuclear.

COMMISSIONER McMURRIAN: Good. And another one along sort of the federal policy debate, I have to ask about the nuclear waste debacle. And do you see that -- I don't know how else to put it. It's been years. Do you see that as a barrier to new nuclear plant construction?

MR. SCROGGS: Again, we see it as an issue that needs to be addressed throughout the process, but we don't see it as a significant barrier. As you're aware, dry cast storage has been an engineered and licensed process for the safe handling and storage of spent fuel. If that were necessary, we could rely on that for a continued period of time.

COMMISSIONER McMURRIAN: Okay. And one last one, Chairman.

I've been hearing a lot and reading some about uranium supply and demand and concerns about whether or not, especially if a lot of the plants that are being proposed come to fruition, that there are concerns about that and at least the price. Can you give us some extra information about that?

MR. SCROGGS: I'm not an expert in nuclear fuel price. I can tell you certainly there is more pressure on the nuclear fuel industry now as the resurgence becomes more palpable, as these projects move towards reality. But nuclear fuel purchasing is done in general on a much longer term contractual basis. There's a lot more stability provided to the pricing by purchasing in very, in large lots in long-term. So it's not as volatile or as liquid as the fuels market for natural gas or for oil.

COMMISSIONER McMURRIAN: That's definitely good. Thank you. Thank you.

CHAIRMAN EDGAR: Commissioners, other questions?

Commissioner Carter.

COMMISSIONER CARTER: Thank you, Madam Chairman. Just a couple of questions.

CHAIRMAN EDGAR: Sure.

COMMISSIONER CARTER: Maybe I didn't hear. I know that my colleagues, Commissioner Skop and Commissioner McMurrian, asked you about the approved standard designs by the Nuclear Regulatory Commission. Did I hear you say whether or not you guys are going to use one of the standard designs or you're going to -- that's what I was listening to.

MR. SCROGGS: We're still in our technology selection process. We have yet to finalize that. And as I said, we've gone through the engineering phase where we've looked technically at all the designs, and we're comfortable that each of these designs will be able to be licensed in the United States, will provide safe and reliable generation. It's more now of determining what leverage and benefits we can obtain in commercial terms and in risk management terms by going with an individual vendor. So we're at that stage of the process now.

COMMISSIONER CARTER: Madam Chairman.

And the NRC came up with these standard designs to shorten the process; correct?

MR. SCROGGS: The NRC has been advocating the industry to develop standardized designs, and the industry has responded by providing a small subset by vendor of a single design that each vendor, or in the case of General Electric, two designs that the vendor is putting forth. And each of those designs, if we were to choose one design from Vendor A, that design would contain all the similar technical specifications, design background that anyone else, any other utility in the United States that would deploy that same technology would have the same diagrams, the same reliability and safety studies supporting it. So it would all be very, very similar.

COMMISSIONER CARTER: And just a final, Madam Chairman.

I think you mentioned in response to a question of Commissioner Skop about five different designs that you were looking at. And I didn't hear, excuse me, just difficult hearing, I didn't hear whether or not you said that of the five which ones were approved by the NRC and which ones you were considering.

MR. SCROGGS: Okay. I'll go through those again. The Westinghouse design is an AP1000, 1,100 megawatts. It is approved as a design, certified design by the NRC. The other design that has been through the design certification process and is approved is General Electric's advanced boiling water reactor. So those are two of the five designs that have achieved design certification.

The other three are in some stage of the design certification review process. General Electric's economic simplified boiling water reactor has been submitted and is under review. The other two candidate technologies are Mitsubishi's, I think it's APR. That, that has been, the design certification document has been developed for that and will be submitted later this year. For the Areva EPR, which is the fifth unit, that is along the same time line. They expect to submit their design certification to the NRC for review within the next six months.

COMMISSIONER CARTER: Thank you, Madam Chair.

CHAIRMAN EDGAR: Commissioners, further questions at this time? No?

Questions from staff?

MR. BALLINGER: I have a couple, if you don't mind.

Mr. Scroggs, earlier you talked about the success of this project would require regulatory commitment and coordination amongst everyone and significant expenditures as we go through. Do you have a ballpark to tell us of the first year or two when we start getting into permitting of expenditures FPL is looking at?

MR. SCROGGS: I think that, that information will be provided more detailed in our need filing in the next near term. But on the order of, of $40 million a year for the next two years would be devoted to the licensing process.

MR. BALLINGER: Okay.

MR. SCROGGS: To support development and initiation of the license reviews at the state and federal level will be on the order of $40 million a year.

MR. BALLINGER: And I think those would be funds that will be discussed in an annual review in cost recovery at the Commission; correct?

MR. SCROGGS: Yes, sir.

MR. BALLINGER: Okay. Thank you.

CHAIRMAN EDGAR: Commissioners, other questions? No? No.

All right. Thank you so much.

Commissioners, next on our agenda it says "Other Related Issues." I'm not sure what that is, so I'm going to ask. Mr. Ballinger, is there another related issue?

MR. BALLINGER: Just trying to be thorough in case something popped up between when the plans were filed and anything else. I don't have anything off the top of my head to discuss. We're open to -- the Commissioners have asked questions they wanted to of the presenters, so I think we can move on to the next topic.

CHAIRMAN EDGAR: All right. Well, let me see. Commissioners, other related issues?

Commissioner Skop.

COMMISSIONER SKOP: Thank you, Madam Chair.

I just was wondering whether, if we have anyone from Progress that might be able to give an update on their 2016 reactor or just a quick status on that.

CHAIRMAN EDGAR: Commissioner, I'm so sorry. I was having a hard time hearing you. Could you repeat that, please?

COMMISSIONER SKOP: Thank you. Yeah. I was just wondering if we happen to have anyone from Progress here today that might be able to comment upon the, their 2016 reactor?

CHAIRMAN EDGAR: I don't know, but we can, we can pose it to the room. Commissioner Skop is asking if there's anybody from Progress who can speak to the 2016 proposal.

Mr. Glenn, thank you for coming forward.

MR. GLENN: I'm Alex Glenn on behalf of Progress Energy Florida.

As part of our balanced solution to serving our customers' needs, we are looking at and continue to look at new nuclear in Florida to meet the 2016 time frame. We are doing that in a thorough, methodical process and analysis, given the significant capital expenditures required for this type of project, and also given the significant risks associated with this type of project, given the scope and the complexity and the time period involved. This is a ten-year time period from concept to actual in-service date in 2016. And when we complete that analysis we'd be happy to give you a very detailed presentation on that when we make a decision and if we choose to move forward with new nuclear for the 2016 time frame. But I'd be happy to answer any questions that you all might have.

COMMISSIONER SKOP: Thank you, Madam Chair.

No. I just was looking for just a quick status update in terms of whether they were, you know, moving forward in that direction. But thank you for that. Appreciate it.

CHAIRMAN EDGAR: Commissioner Argenziano.

COMMISSIONER ARGENZIANO: Yes. Given the time frame and how quickly and how many problems could arise, do you have an idea of when you may, you know, the company may make some decisions?

MR. GLENN: By the end of this year in all likelihood.

COMMISSIONER ARGENZIANO: By the end of the year.

MR. GLENN: We are continuing to negotiate with our vendor. We have selected a technology. It is the AP, the Westinghouse AP1000 pressurized water reactor technology. That's 1,100 megawatts. And our desire is to put two units at the Levy County nuclear site, so that would be 2,200 megawatts going in in 2016 and 2017, with a need application by January of '08 to meet the 2016 in-service date with our filing with the DEP for site certification application following that shortly.

However, we are still continuing to evaluate really the critical issues, which are: Financial, what is the cost going to be ultimately? What are the financial risks? What are the technical risks associated with this project? What are the reputational risks? This may not be a completely popular decision to build new nuclear, and particularly with associated transmission facilities that will be required to put such a large unit onto our system. So that analysis is still ongoing with the company, but we anticipate that we will make a decision by the end of the year.

COMMISSIONER ARGENZIANO: And if you feel, if the company decides to go forward, do they feel that the end of the year will give them enough time to make that deadline, 2016?

MR. SCROGGS: Absolutely. We're already, Commissioner Argenziano, we're already taking steps. We actually have 21 NRC inspectors onsite at our Levy County site on Monday and Tuesday of next week. We are preparing the COLA application. We are taking all steps necessary at this time to preserve that option. But again -- and that would allow us to have a -- if all, like Mr. Scroggs indicated, if all things, the stars align, that would support a June 2016 in-service date. But that's a significant and it's an aggressive schedule, but it can be, it can be achieved. But, again, you know, the regulatory risks, the financial risks and the technical risks we're still evaluating.

COMMISSIONER ARGENZIANO: Thank you.

CHAIRMAN EDGAR: Any other questions for Mr. Glenn at this time?

Commissioner Skop.

COMMISSIONER SKOP: Thank you, Madam Chair.

I just wanted to thank you for that, for that quick overview and with respect to the additional discussion on the technology choice and some of the other related details. So thank you again.

MR. GLENN: Sure.

CHAIRMAN EDGAR: Thank you, Mr. Glenn.

And next on our agenda we have public input. Mr. Ballinger, are you aware of anybody who has asked to speak to address the Commission at this time?

MR. BALLINGER: I'll let Katherine address that. I don't think so.

CHAIRMAN EDGAR: Ms. Fleming.

MS. FLEMING: We are not aware, we haven't been contacted by anyone. But if -- I would suggest that we check to see if anyone is here that we're not aware of.

CHAIRMAN EDGAR: Absolutely. And so for those of you that are with us here this morning, is there anybody that would like to address the Commission at this time on the subject of the Ten-Year Site Plans? No?

All right. Well, thank you all for your interest. Thank you to our presenters. A lot of excellent, excellent information. Commissioners, thank you for your questions, and to our staff. And we are adjourned.

(Workshop adjourned at 11:20 a.m.)

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

I, LINDA BOLES, RPR, CRR, Official Commission Reporter, 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' attorneys or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 20th day of August, 2007.

Linda Boles

LINDA BOLES, RPR, CRR
FPSC Official Commission Reporter
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2007

Ten-Year Site Plan Workshop

FRCC Studies and Reports

August 15, 2007

Parties/Staff Handout
event date 08/15/07
Docket No. Undocketed

FLORIDA RELIABILITY COORDINATING COUNCIL

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2007
Load & Resource Reliability Assessment Report

FLORIDA RELIABILITY COORDINATING COUNCIL

Approved by Planning Committee
July 25, 2007

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Executive Summary

One of the primary functions of the Florida Reliability Coordinating Council (FRCC) is to assess the reliability of the Bulk Power Electric System in the region. As part of this annual assessment, the FRCC aggregates load and resource data addressing the next ten years. Data is received from its members and used to develop the resulting Regional Load & Resource Plan and this Reliability Assessment Report which are submitted to the Florida Public Service Commission (FPSC).

The majority of new generators being built in the FRCC Region use natural gas as their primary fuel. Currently, generators using natural gas provide approximately 39% of the energy in the FRCC Region; however, by 2016 it is forecasted that 45% of the energy in the FRCC Region will be provided by generators using natural gas as their primary fuel. The Regional Load & Resource Plan, based on January 1, 2007 forecast data, includes the addition of about 4,000 MW of new coal-fired capacity, much of which has recently been cancelled or placed in jeopardy. Assuming this capacity is converted to gas, Florida's reliance on natural gas for generating electricity will rise to about 53% by 2016.

This increase in dependency on natural gas and possible interruptions to the fuel transportation infrastructure could have an impact on the reliability of generation resources in the FRCC Region. FRCC has undertaken initiatives to increase coordination among natural gas pipeline operators and electric generators within the region. In addition, FRCC worked with a consultant that utilized a transient gas flow model to simulate fuel flows into the pipeline system under a variety of scenarios. Preliminary results have shown no significant risk over the next 5 years. However, FRCC is reviewing these results to determine how recent developments (coal plant cancellations, Governor's July 13, 2007 Executive Orders, etc.) will impact projected system reliability.

In summary, the findings of the 2007 Reliability Assessment of the FRCC Region are:

- Reserve margins for the FRCC Region for the summer and winter peak hours equal or exceed 15% for the ten-year period.;
- Generation reliability is expected to be adequate for the Region during the ten-year planning period;
- The natural gas pipeline capability is expected to be adequate for the next five years. The FRCC will assess the adequacy of the pipeline in the second five years with the likely increased reliance on natural gas with the cancellation of coal-fired generation; and,
- The load forecast is reasonable and sound.

Reserve Margin Review

The FRCC has a resource adequacy standard requiring a 15% regional reserve margin based on firm load. FRCC reserve margin calculations include merchant plant capacity that is under firm contract to load-serving entities. The FRCC assesses the upcoming ten-year summer and winter peak hours on an annual basis to ensure that the regional reserve margin requirement of 15% is satisfied. Since the summer of 2004, the three Investor Owned Utilities (Florida Power & Light Company, Progress Energy Florida, and Tampa Electric Company) are currently maintaining a 20% minimum reserve margin planning criterion, consistent with a voluntary stipulation agreed to by the FPSC, while all other utilities employ a 15% minimum reserve margin planning criterion.

For any peak period that the regional reserve margin requirement is not met, a thorough assessment will be conducted and this assessment will be forwarded to the FRCC Board of Directors and to the Florida Public Service Commission for review.

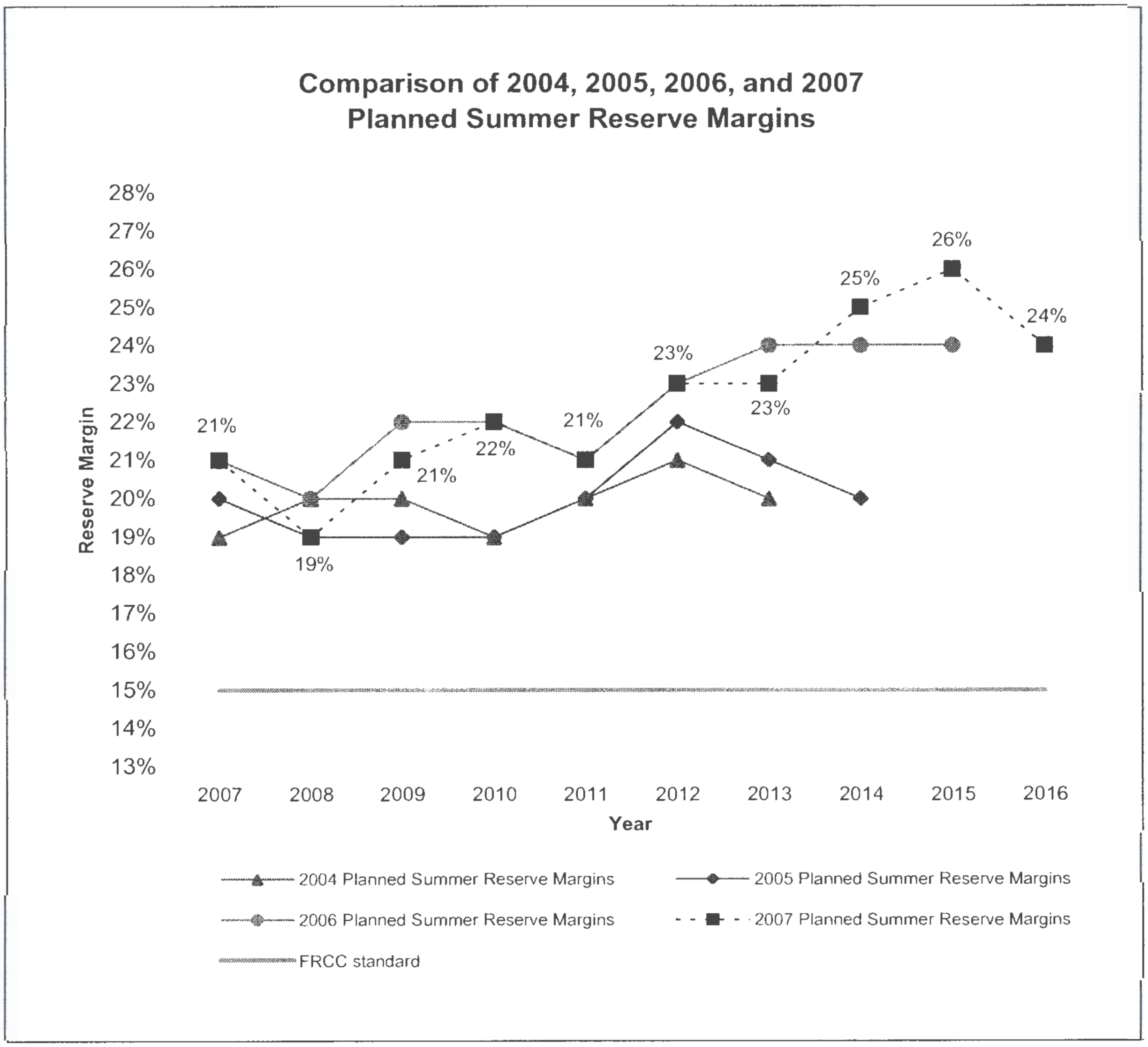

Figure 1

Figure 1 shows that the summer reserve margins from the 2007 Regional Load & Resource Plan continues to be over and above the FRCC's reserve margin requirement. The reserve margins in the 2007 Regional Load & Resource Plan equal or exceed 20% for every year in the ten-year forecast period except 2008 which is 19%.

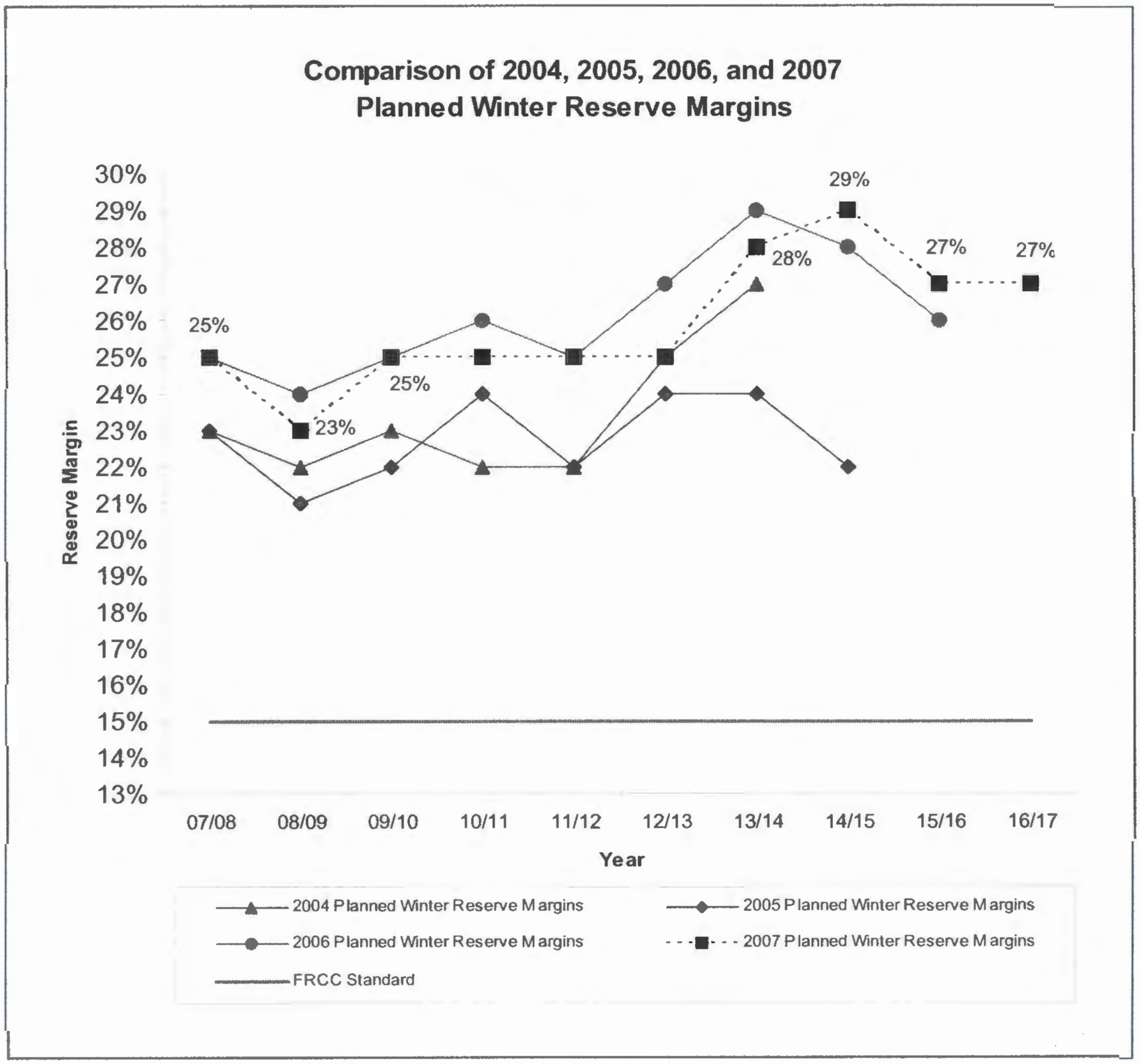

Figure 2

In a similar manner, ***Figure 2*** shows the winter reserve margins from the 2004, 2005, 2006, and 2007 Regional Load & Resource Plans. The winter reserve margins in the 2007 Regional Load & Resource Plan are over 20% for every year in the ten-year forecast period.

FRCC Resource Adequacy Criteria Review

Introduction

The FRCC Resource Adequacy Review process looks at several metrics to determine resource adequacy for the FRCC Region. Periodic reviews of Loss of Load Probability (LOLP) every 3 – 5 years, along with annual reviews of generator Forced Outage Rates (FOR) and Availability Factors (AF), are performed in addition to the Reserve Margin review to determine if the planned resources for the FRCC Region will meet FRCC, FPSC and NERC requirements for resource adequacy.

LOLP Analysis

The FRCC has historically used the LOLP analysis to establish the adequacy of reserve levels for peninsular Florida. The LOLP analysis uses system generating unit information to determine the probability that existing and planned resource additions will not be sufficient to serve forecasted loads. The objective is to establish resource levels such that the specific resource adequacy criterion of a maximum LOLP of 0.1 day in a given year is not exceeded. In order to maintain the resource level that satisfied this criterion, the FRCC established a regional Reserve Margin Planning Standard (also known as a Resource Adequacy Standard) of 15% reserve margin versus firm load.[1]

The most recent LOLP analysis was conducted in 2006 that examined forecasted LOLP values under "most likely" conditions, along with impact of other extreme scenarios (e.g., extreme seasonal demands; no availability of firm and non-firm imports into the region;

[1] The FRCC Executive Committee adopted the Reserve Margin Planning Standard in September 1998.

and the non-availability of Demand Side Management, specifically load control programs). The analysis indicated that for the "most likely" and extreme scenarios, the peninsular Florida electric system maintains a LOLP well below the criterion for the ten year study horizon. The RWG recommends on the basis of the 2006 LOLP study results that the 15% Reserve Margin Planning Standard be maintained.

Forced Outage Rates (FOR) and Availability Factors (AF)

Generating unit reliability is a primary driver of loss of load probability results. As LOLP studies are extremely data and time intensive, the RWG has separately monitored two unit performance measures for individual utility systems and the Region as a whole to serve as a proxy indicator for the reliability of the Region. These metrics are capacity-weighted Forced Outage Rate (FOR) and the capacity-weighted Availability Factor (AF) for each utility system. The individual utility system information is aggregated to develop FRCC regional values for FOR and AF. Actual and forecasted FOR and AF values are then trended and compared to historic values, where demonstration of utility and regional stability and/or improvement in these performance measures serves as an implicit indicator that the established LOLP criterion is not being exceeded.

In the current analysis, both yearly capacity-weighted FOR and AF values for each utility system were again calculated. The calculations were based on each utility's latest planning assumptions (i.e., assumptions developed and used in the utility's 2006 resource planning work and which is subsequently reported in the utility's 2007 Ten Year Site Plan and used in the 2007 Reliability Assessment). The 2006 FOR and AF values were compared to the values calculated from previous years' analyses conducted using 2003, 2004 and 2005 data.

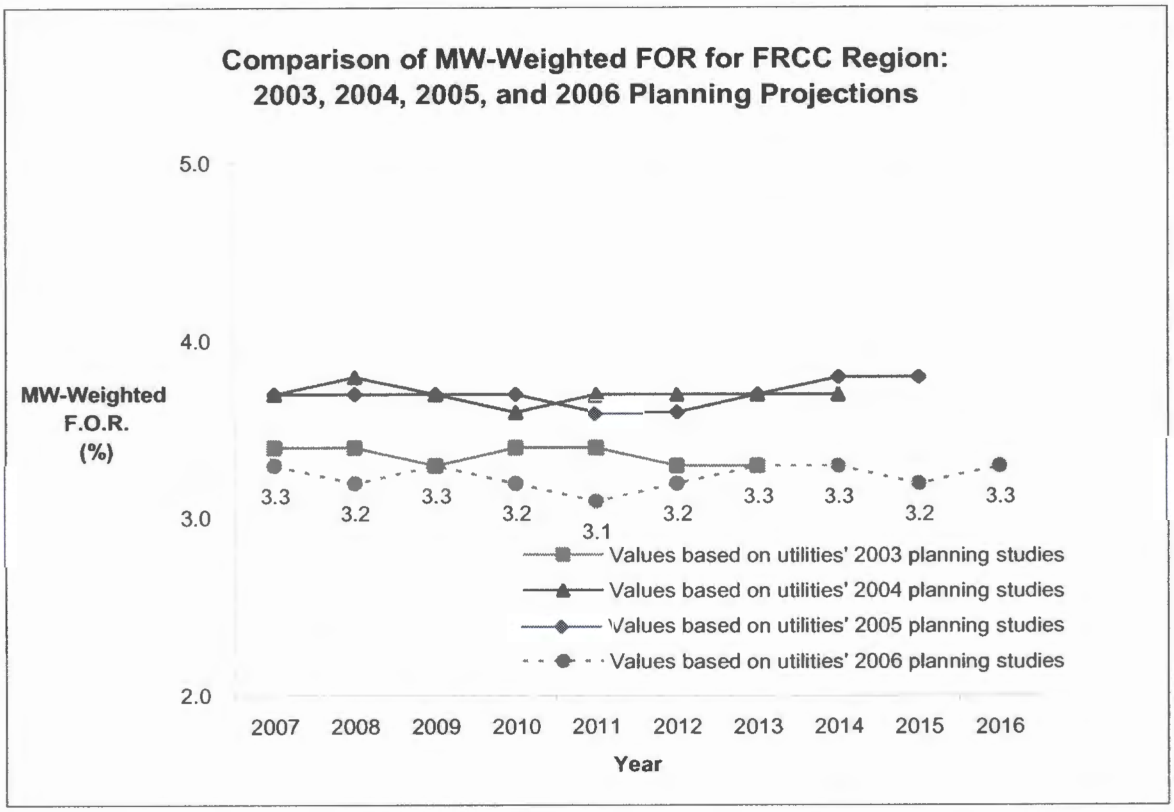

Figure 3
Trends in Forced Outage Rate (FOR)

As seen in ***Figure 3***, the 2006 projections of FOR have decreased in magnitude (improved) in comparison to projections made using 2003 through 2005 data. In addition, the general trend in the forecasted FOR rates is flat over time, indicating that the Peninsular Florida system is stable and is maintaining its reliability over time. Consequently, these results lead to the conclusion that Peninsular Florida system will continue to remain a reliable system. FOR data is a key input to LOLP studies. High or increasing FORs typically yield high or increasing LOLP values. This indicates a higher or increasing probability that load will not be served in a given hour. Because of that relationship, the monitoring of FOR is a reasonable proxy indicator for the reliability of the Region.

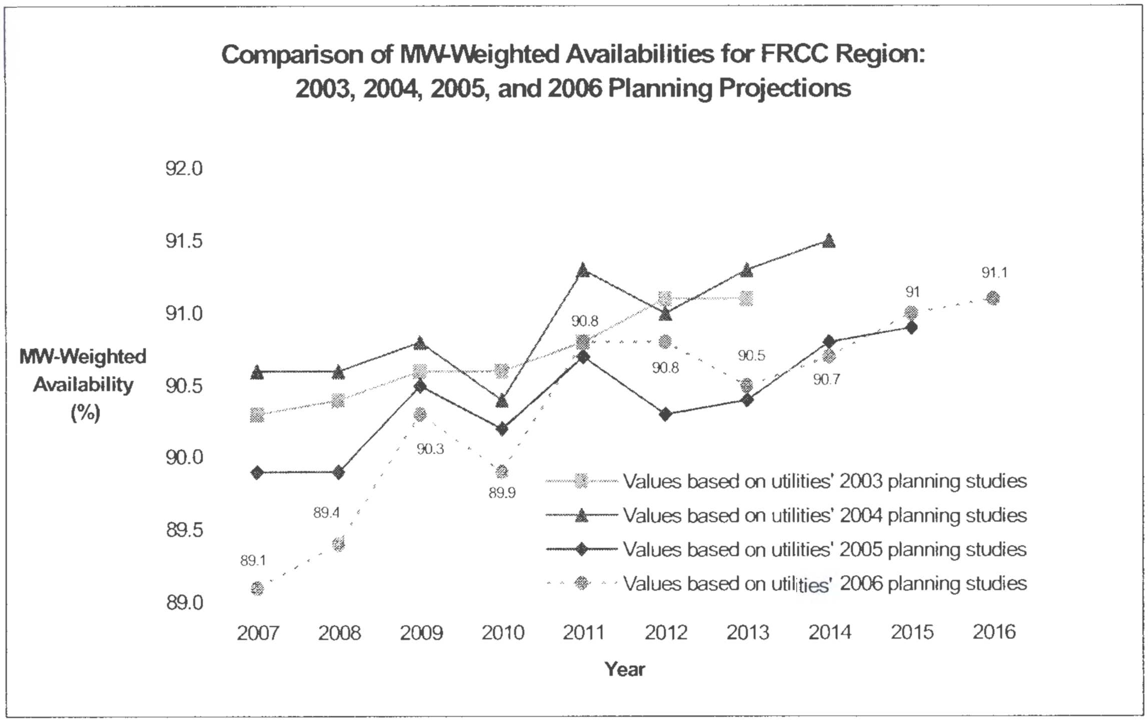

Figure 4
Trends in Availability Factor (AF)

Though not an input to LOLP calculations, the generating unit Availability Factor is often used as an indicator that correlates well with FOR data. ***Figure 4*** shows that projections of MW-weighted Availabilities have been consistent from year to year indicating that the generators are being reasonably maintained and are available to serve load. Radical changes in AF values from year to year would raise questions regarding the availability of the units to serve load when called upon and question their overall reliability. The drop in the 2007 and 2008 availability values are attributed to lengthy unit outages during those time frames to comply with Clean Air requirements that start taking affect in 2009. This is expected to be a one time aberration in the data as utilities get their units into compliance. Combined with the results of the FOR trend depicted in ***Figure 3***, this trend in availability supports the conclusion that Peninsular Florida will continue to be a very reliable system.

Resource Adequacy Review Process

The analyses results discussed in the previous section followed the FRCC's Resource Adequacy process that was completed last year. A brief summary of that review follows:

1. Review of statistics used for tracking system performance

   As previously presented, the FRCC RWG performs periodic LOLP studies and annual reviews of system wide FOR and AF as indicators of resource adequacy. The FRCC RWG assessed the option of using modified indices in place of FOR and AF as reliability indicators, but determined that such indices would not provide new information. Present indices are still effective in identifying trends that indicate whether the reliability of the peninsular Florida system is changing (becoming more reliable or less reliable) over time from an LOLP perspective. RWG has concluded that it is appropriate to continue the use of FOR and AF as reliability measures in place of performing extensive LOLP analyses. The potential for new NERC data requirements in the future may require other analyses.

2. Fuel Deliverability

   The increase in dependency on natural gas and possible fuel supply or delivery disruptions may impact the adequacy of FRCC resources to meet customer load and thus should be considered in resource adequacy reviews. The FRCC has undertaken initiatives to increase coordination among natural gas pipeline operators and generators within the region. The FRCC, through its Gas Electricity Interdependency Task Force (GETF), has commissioned a deliverability study. The consultant utilized a transient gas flow model to simulate fuel flows into the pipeline system under a variety of scenarios. Preliminary results have shown no significant risk over the next 5 years. The FRCC is reviewing these results to determine if any additional analysis is needed.

3. Transmission Capability

The FRCC Transmission Working Group (TWG) provides the RWG with information that may be used in the annual Reliability Assessment to determine if additional studies need to be completed to evaluate the impact of transmission constraints on generation.

4. Environmental Compliance

The FRCC RWG concludes that current environmental requirements imposed by federal, state, and local authorities that may impact the capacity and operation of generation resources are adequately accounted for within the resource adequacy process through the individual utility resource planning processes. Any utility or generator specific emission limitations and/or environmental compliance costs are presently captured by incorporating these in the production costing models used in the resource planning process.

The impact of the recent Executive Orders such as Florida Governor Crist's July 13, 2007 Order will have an impact on the type of future generating resources to be built to serve the Region's growing load. Each utility will be planning their respective systems in accordance with such Orders and those effects will be captured as the utilities submit their annual planning data.

Future Work on Resource Adequacy

The LOLP process uses probabilistic analysis to quantify the ability of the generation system resources to reliably meet expected demand, incorporating the uncertainties associated with generation reliability including unit outage rates, maintenance schedules, load uncertainty, demand-side management and support from an assistance area. It should be recognized that overall resource adequacy must also account for considerations such as transmission constraints and fuel deliverability. The RWG reviewed these considerations along with the LOLP analytical process in 2006, and recognized areas that can be addressed to add more depth and detail to the resource adequacy analysis.

FRCC will continue to conduct various studies to ensure regional resource adequacy. The Resource Working Group plans to address the following:

1. <u>LOLP Analysis</u>

   - <u>Load Forecast Uncertainty</u>

     The current modeling approach assumes the most likely load forecast prevails (with the exception of extreme summer and winter sensitivities). The statistical uncertainty of the forecasted load has been developed and will be incorporated in a coordinated manner in future studies.

- <u>Major Maintenance Schedule Variation</u>

  The current modeling approach uses standard maintenance schedules projected by member utilities for their units. Any deviations from planned schedules may impact the projected LOLP.

2. <u>Transmission Constraints</u>

   The current modeling approach assumes that sufficient transfer capability exists between all utility systems within the FRCC region and SERC (with the exception of sensitivities where SERC transfer is explicitly limited or precluded). TWG reviewed each utility's ability to import power for the loss of internal generation and each utility's ability to export their share of operating reserves and determined that the transmission system was adequate for these scenarios. RWG, in conjunction with TWG, will review this assumption and develop a plan for addressing transmission constraints in future resource adequacy reviews.

3. <u>Fuel Deliverability</u>

   The RWG will review the GETF's deliverability study, and incorporate appropriate observations or recommendations in future resource adequacy reviews.

FRCC Load Forecast Evaluation

The current demand for electricity by Florida consumers continues to expand driven primarily by continued strong growth in population and a vibrant economy. Since 2005 there has been a softening of the housing construction market, increasing mortgage rates, high energy prices, frequent hurricanes and a surge in the cost of living and affordability index. Nevertheless, Florida continues to have one of the best economies in the nation, with below the national average in unemployment rates and a leader in job creation. Residential construction activity has declined from the record levels observed in 2005 but commercial and industrial construction continues to expand at a good rate. Most real estate analysts concur that the current slowdown in the residential construction market should last between 12 and 18 months by which time the excess housing inventory should be absorbed and construction activity return to traditional levels of growth. The continued strong migration to Florida suggests a sustained demand for housing and a nonstop economic expansion for the foreseeable future. The projection of future demand for electricity will account for these variants to ensure that neither an overstatement nor understatement of this component of future demand is reflected in FRCC load forecasts.

The FRCC Load Forecast was thoroughly scrutinized to account for the current volatility in most macro-economic factors, the current housing market slow down, and an assessment of how the individual member utilities are accounting for the high fuel and price of electricity forecast. Florida's economic outlook, historical forecast variances and benchmarking with recent history constituted the other elements that were inspected in this evaluation process.

The impact of the 2005 Energy Act on load growth was analyzed. Whereas, some utilities have attempted to incorporate this impact on the load forecast, a number of utilities are still struggling on how to quantify the impact on future load growth. The load forecast evaluation process served as a vehicle to discuss possible means to estimate this impact and the need to incorporate it into the load forecast.

The FRCC Load Forecast is an aggregation of the load forecast of each of its member utilities. FRCC has pursued this avenue since it is only logical to assume that each utility is most familiar with its own service territory. The load forecast evaluation process undertaken by FRCC is to ensure that each utility in preparing this outlook is availing itself of the best available information in terms of data, forecasting models and to a certain degree consistency of assumptions across all utilities. FRCC's Load Forecasting Task Force (LFTF) reviewed in detail each utility's forecast methodology, input assumptions and sources, and output of forecast results. Sanity checks were performed comparing the historical past with the projected load growth, use per customer, weather-normalized assumptions, and load factors.

Although a significant amount of advancement has been achieved in the science of forecasting and statistical modeling, there still remains an amount of risk or forecast variance associated with the uncertainties imbedded in the primary factors that determine the demand for electricity. The uncertainties that are most noticeable are departures from historical weather patterns, recent population growth, performance of the local and national economy, size of homes and number of homes being built, price of fuel, inflation, interest rates, price of electricity and other factors. In the short-run, weather deviations from normal are most important but population growth, economic performance and price of electricity play crucial roles in explaining the growth in demand for electricity over the long-run. The load forecast should provide an unbiased estimate of the level of the future load after accounting for these uncontrollable factors. The projections of load should not consistently under or over forecast the actual loads. Additionally, it is desirable that the forecasting processes used by the member utilities of FRCC exhibit continuous improvement that can be measured by the size of the weather-normalized forecast variance.

Methodology

The FRCC's evaluation process of each individual member's load forecast and forecasting methodologies comprised the following:

Models

Review and technically assess the properties and theoretical specifications of the forecasting models utilized to develop the individual utility's forecast without recommending or endorsing a particular type of model. There is an evident preference for econometric models over end-use modeling by the utilities in the state of Florida. However, there were some utilities that found it advantageous to combine econometric models with other types of forecasting models (which were basically hybrids of end-use and econometric models). The ultimate measure of how well a model is performing is the size of the weather-normal forecast variance. The LFTF was attentive as to the forecasting results, and cannot categorically endorse one type of model over the other based upon the results obtained. The LFTF does not consider it prudent to standardize the types of forecasting models to be used in Florida because each service territory is different and certain types of models seem to yield better results under specific conditions. The FRCC's review ensures that all employed models portray good statistical properties with correct specifications between the key factors affecting the level of demand for electricity and the resulting load forecast. It is customary that all utilities update and refine their models with each additional year of actual data, which ensures that the most recent correlations and associations imbedded in the data are captured and that the models are calibrated accordingly. Furthermore, this ensures that the starting point of each forecast series is adjusted to the latest historical value for load or customer growth.

Inputs

The input assumptions that feed the forecasting models used to project load as well as the sources of these inputs were assessed. The primary inputs that were examined included Florida population and customers, the price of electricity, normal weather assumptions, economic outlook and saturations of electrical appliances in those models that combine end-use technology with econometric modeling. The source data for Florida's population was the Bureau of Economic and Business Research from the University of Florida and from Moody's Economy.com, a reputable forecasting firm. The price of electricity was derived internally by each utility and consisted of base rates and fuel clauses filed with the Florida Public Service

Commission (FPSC). The National Oceanographic and Atmospheric Administration (NOAA) provided all historical weather used in model estimation and calibration. Given that each utility's service territory has its own characteristics, different time horizons were used to determine the values for normal weather that best fits their specific distinctiveness. As such, some utilities employed the average weather over the last 20 years, others the last 30 years, and some used longer time periods to define what was considered as "normal" weather. There is no prescribed correct measure of "normal" weather and utilities will rely on the definition that best portrays the observed weather patterns in their service territory. This definition of "normal" weather is then employed throughout the forecast horizon, implying that an "abnormal" weather outlook would not be an assumption and would not be a factor in projecting load. All utilities assumed a "normal" weather outlook. The economic outlook of the local and national economy was obtained from several reputable economic forecasting firms such as Global Insight (Formerly DRI-WEFA) and Moody's Economy.com. The utilities across the State are practically split evenly among those using Global Insight and those using Economy.com. Both firms are highly regarded in the industry. By using more than one firm, the risks of producing flawed results were minimized because somewhat different economic perspectives were relied upon.

Outputs

To assess the quality of the load forecasts two measures were employed. The current forecast was compared to the (1) prior forecast developed last year and (2) to the recent historical past. The 2007 load forecast is slightly lower than the 2006 forecast in the later years of the forecast horizon reflecting the effect of additional conservation and load control measures, a slightly less optimistic economic outlook (but still a good economic outlook), high prices of electricity which compensates for the higher outlook on population growth in Florida. The higher population outlook reflects the continued good growth in customers as Florida expands with job seekers migrating from other states due to the availability of jobs. The population projections released annually by the University of Florida have increased slightly the outlook for the number of residents in the coming years. The current migration to Florida consists of job seekers, people coming with jobs, or those seeking investment opportunities. Florida's economic outlook, while still very strong is not as buoyant as last year's outlook due to the slowdown in residential construction. Nevertheless, the other sectors of the Florida economy continue to perform superbly. The countervailing force that dampened the growth outlook was the projected price of fuels and its ensuing effect on the future price of electricity for Florida's customers.

The projected summer peak was also adjusted downward as a result of the U.S. Energy Policy Act of 2005 that mandates certain conservation measures such as: higher appliance efficiencies, more efficient commercial lighting structures, and federal buildings upgraded codes.

Load Factor

Several other ad-hoc measures were examined to assist in the determination of the reasonableness of the load forecast. The load factor, which is the relationship between the average load and the peak load, was examined comparing projected with historical values for this parameter. Ensuring that historical and projected load factors were aligned helped to provide an increased level of assurance that no given component of the load forecast was out of line. All member utilities exhibited similar load factors when comparing these values in the historical and projected periods. Furthermore, the pattern of a slight increase or growth in the load factor is projected to carry on into the forecast horizon but still in line with observed historical values over the last ten years. The decrease in load factor observed in 2005 (see ***Figure 8***) is a product of abnormally hot weather inflating the peak values and a depressed average load due to hurricanes. The load factors were back in line again in 2006 when weather was more similar to normal.

Florida Reliability Coordinating Council
Comparison of 2006 and 2007 Forecasts

Summer Peak				
	Forecast		Difference	
Year	2006	2007	MW	%
2007	46,725	46,878	153	0.3%
2008	48,030	48,037	7	0.0%
2009	49,233	49,280	47	0.1%
2010	50,221	50,249	28	0.1%
2011	51,343	51,407	64	0.1%
2012	52,490	52,464	-26	0.0%
2013	53,686	53,548	-138	-0.3%
2014	54,830	54,622	-208	-0.4%
2015	56,130	55,896	-234	-0.4%

Winter Peak				
	Forecast		Difference	
Year	2006	2007	MW	%
2007 / 08	49,464	49,526	62	0.1%
2008 / 09	50,732	50,737	5	0.0%
2009 / 10	51,678	51,673	-5	0.0%
2010 / 11	52,869	52,780	-89	-0.2%
2011 / 12	53,923	53,872	-51	-0.1%
2012 / 13	55,086	54,986	-100	-0.2%
2013 / 14	56,271	56,155	-116	-0.2%
2014 / 15	57,674	57,468	-206	-0.4%
2015 / 16	59,162	58,853	-309	-0.5%

Values are non-coincident peaks

Figure 5

Results

The major differences between the 2006 and 2007 forecasts is that the latter forecast assumes a higher population growth, slightly less optimistic economic outlook and high price of electricity. The comparison between the 2006 and 2007 forecasts in terms of the Summer Peak shown in ***Figure 5*** reveals a similar projected Summer Peak (slightly higher) for the first five to six years and slightly less in the latter years for the most recent forecast. The increase in Summer Peak forecast seen in the early years is not maintained throughout the forecast horizon because the full impact of the U.S. Energy Policy Act of 2005 is not felt until the latter years of the forecast horizon and because of additional demand side management programs to be implemented by the member utilities.

Over the past ten years, Peninsular Florida has averaged approximately 1,303 MW of growth in summer peak per year, while current projections have this growth at 1,146 MW per year. In 2005, the growth in summer peak was just over 3,700 MW, three times the average growth, due primarily to the record setting average temperatures across the state. In 2006 the growth in summer peak was a negative 579 MW (-1.3%) which reflects the abnormal weather in 2005 compared to 2006. In the load forecast evaluation process FRCC ensured that all the utilities adjusted the starting value of the outlook to account for the normal historical weather and load.

With regard to the Winter Peak, the 2007 forecast is also higher than the 2006 forecast in the early years of the forecast horizon and then becomes progressively lower in the latter years of the forecast horizon. The small difference between forecasts for these years is a reflection of the slightly less optimistic economic forecast. The population projections by the University of Florida are slightly higher than in the 2006 forecast and the fact that most Winter Peak models either don't have a price component or have very low price elasticity would suggest a higher winter peak forecast but the current economic outlook dampens these other two factors. For the latter years of the forecast, the 2007 winter peak forecast is also lower than the 2006 forecast because it incorporates a significant reduction in load due to additional conservation and load control measures to be implemented by the member utilities. The impact of the U.S. Energy Policy Act of 2005 increases through time as sufficient time is allowed for the current stock of less efficient appliances to be depleted and replaced by more efficient ones.

The confidence level that can be placed on these forecasts can be deduced by examining the historical performance of FRCC's forecasts. The summer peak analysis, shown in ***Figure 6***, clearly indicates that a tendency to under or over forecast is not present in the FRCC aggregate ten-year load forecast. The first column in ***Figure 6***, labeled "Actual Summer Peak (MW)", corresponds to the actual observed summer peak. The next ten columns show the forecast as it was presented in the Regional Load & Resource Plan for each of the ten years listed from 1997 through 2006. The bottom half of the table is the percent forecast variance, derived by comparing actual to forecast demands. A positive variance means that the "actual" was larger than the forecasted value for the corresponding year, meaning an under-forecast. A negative forecast variance means an over-forecast.

COMPARISON OF PRIOR SUMMER PEAK FORECASTS
(MW)

Year	Actual Summer Peak (MW)	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
1997	32,924	34,566									
1998	37,153	35,642	35,633								
1999	37,493	36,172	36,628	36,788							
2000	37,379	37,079	37,410	37,541	37,728						
2001	38,670	37,894	38,220	38,223	38,445	38,478					
2002	39,903	38,530	38,844	38,959	39,282	38,548	40,145				
2003	40,417	39,197	39,395	39,781	40,157	40,783	41,335	41,618			
2004	42,172	39,890	40,227	40,593	41,004	41,714	42,292	42,668	42,705		
2005	45,924	40,698	41,112	41,433	41,905	42,644	43,279	43,670	43,753	43,495	
2006	45,345	41,385	41,998	42,398	43,190	43,782	44,274	44,727	44,826	44,680	45,520

FORECAST VARIANCE
(PERCENT)

Year	Actual Summer Peak (MW)	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
1997	32,924	-4.8%									
1998	37,153	4.2%	4.3%								
1999	37,493	3.7%	2.4%	1.9%							
2000	37,379	0.8%	-0.1%	-0.4%	-0.9%						
2001	38,670	2.0%	1.2%	1.2%	0.6%	0.5%					
2002	39,903	3.6%	2.7%	2.4%	1.6%	3.5%	-0.6%				
2003	40,417	3.1%	2.6%	1.6%	0.6%	-0.9%	-2.2%	-2.9%			
2004	42,172	5.7%	4.8%	3.9%	2.8%	1.1%	-0.3%	-1.2%	-1.2%		
2005	45,924	12.8%	11.7%	10.8%	9.6%	7.7%	6.1%	5.2%	5.0%	5.6%	
2006	45,345	9.6%	8.0%	7.0%	5.0%	3.6%	2.4%	1.4%	1.2%	1.5%	-0.4%

Actual values are non-coincident peaks

Figure 6

The Forecast Variance section for the table shown in ***Figure 6*** provides additional information. For example, beginning in 1999 up to 2004, the forecast variances have been extremely low indicating remarkable accuracy for the first few years of the forecast period. The year 2005 is an outlier and reflects the effects of the "abnormal" weather in this year as described above. In 2006, where the summer weather was considered normal, the forecast variance was once again very small. In 2006, the FRCC forecast missed its target by only -0.4% or 175 MW out of a forecast of 45,520 MW. If we momentarily disregard 2005, the actual observed summer peak load is very similar to the load that was projected in the FRCC aggregate load forecast for most of these years.

This suggests that the methodology employed by FRCC and its member utilities to project load for the region is unbiased and improving.

COMPARISON OF PRIOR WINTER PEAK FORECASTS (MW)

Year	Actual Winter Peak (MW)	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
1997 / 98	30,932	38,090									
1998 / 99	35,907	39,091	39,450								
1999 / 00	36,394	40,026	40,383	39,989							
2000 / 01	40,258	40,961	41,395	40,928	40,894						
2001 / 02	39,675	41,737	42,219	41,865	41,811	42,208					
2002 / 03	44,472	42,589	42,998	42,808	42,739	43,508	43,199				
2003 / 04	35,564	43,467	43,925	43,726	43,663	44,487	44,219	44,266			
2004 / 05	41,090	44,374	44,895	44,651	44,638	45,461	45,237	45,301	45,418		
2005 / 06	43,202	45,304	45,896	45,553	45,694	46,454	46,242	46,419	46,546	46,717	
2006 / 07	42,107	46,188	46,879	46,600	46,668	47,589	47,215	47,561	47,692	47,994	48,296

FORECAST VARIANCE (PERCENT)

Year	Actual Winter Peak (MW)	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
1997 / 98	30,932	-18.8%									
1998 / 99	35,907	-8.1%	-9.0%								
1999 / 00	36,394	-9.1%	-9.9%	-9.0%							
2000 / 01	40,258	-1.7%	-2.7%	-1.6%	-1.6%						
2001 / 02	39,675	-4.9%	-6.0%	-5.2%	-5.1%	-6.0%					
2002 / 03	44,472	4.4%	3.4%	3.9%	4.1%	2.2%	2.9%				
2003 / 04	35,564	-18.2%	-19.0%	-18.7%	-18.5%	-20.1%	-19.6%	-19.7%			
2004 / 05	41,090	-7.4%	-8.5%	-8.0%	-7.9%	-9.6%	-9.2%	-9.3%	-9.5%		
2005 / 06	43,202	-4.6%	-5.9%	-5.2%	-5.5%	-7.0%	-6.6%	-6.9%	-7.2%	-7.5%	
2006 / 07	42,107	-8.8%	-10.2%	-9.6%	-9.8%	-11.5%	-10.8%	-11.5%	-11.7%	-12.3%	-12.8%

Actual values are non-coincident peaks

Figure 7

The analysis for winter peaks is shown on ***Figure 7.*** A perfunctory review would suggest a tendency to over-forecast given the predominance of projected peaks higher than the observed "actuals". Weather and temperature variations typically differ from the "normalized" weather assumptions used to develop the individual utility electric forecasts. In Florida, this is much more pronounced for the winter months compared to the summer months. Therefore, this weather volatility caused a significantly larger number of over-forecast occurrences because since 1997 there has been only one year, 2003, with colder than normal winter seasons for the State of Florida as a whole. A good example of this volatility can be seen comparing the peaks of 2003 and 2004. The year 2003 had a cold winter and the total demand of electricity reached a record of 44,472 MW of peak winter demand. Conversely, the year 2004 was very mild and the peak demand reached only 35,564 MW, a drop of 8,908 MW in peak demand between successive years. Since 2003, Florida has not experienced a cold winter and as such the winter peak load since 2003 has not reached the peak observed in that year. Florida does not experience a cold winter very often. Nevertheless, each utility in its resource plan considers the eventuality of a severe winter peak and plans for it.

Several factors account for the divergence between "actual" and "projected" (forecast variance) besides weather and temperature. These factors center on conditions that lead to short-term deviations that cycle above and below long-term trends. Unanticipated customer growth and better than expected economic conditions over the short-term can differ from the long-term assumptions used to develop the forecast. The FRCC forecast does not attempt to capture these short-term deviations but to portray the most likely outcome in terms of projected load for the state of Florida over the next ten years.

Finally, ***Figure 8*** shows a comparison between the historical load factors (for 1997 through 2006) and the projected load factors based on the summer peak. The summer peak was chosen because it is less volatile than the winter peak, which fluctuates widely over the historical years since cold winters have occurred only sporadically. Both historical and forecasted load factors are similar in magnitude. This provides comfort in knowing that both the average loads and peak loads are growing at a comparable rate.

FRCC LOAD FACTORS
Based on Summer Peak

Year	Load Factor
1997	0.609
1998	0.577
1999	0.574
2000	0.601
2001	0.594
2002	0.603
2003	0.620
2004	0.595
2005	0.563
2006	0.579
2007	0.583
2008	0.590
2009	0.592
2010	0.596
2011	0.600
2012	0.605
2013	0.607
2014	0.611
2015	0.613

Figure 8

As a result of this evaluation, the FRCC LFTF concludes that the load forecast is suitable and reasonable and can be used for reliability assessment purposes.

B

FRCC Revised Regional Transmission Planning Process

FLORIDA RELIABILITY COORDINATING COUNCIL

Approved by Planning Committee
May 2, 2007

Approved by Board of Directors
July 24, 2007

FRCC REGIONAL TRANSMISSION PLANNING PROCESS

The objective of the FRCC Regional Transmission Planning Process ("Planning Process") is to ensure coordination of the transmission planning activities within the FRCC Region in order to provide for the development of a robust transmission network in the FRCC Region.

RESPONSIBILITY

The FRCC Board of Directors ("Board") shall have the responsibility to ensure this process is fully implemented.

The FRCC Planning Committee ("Planning Committee") shall direct the Transmission Working Group ("TWG"), and the Stability Working Group (SWG), as appropriate, in conjunction with the FRCC staff, to conduct the necessary studies to fully implement the Planning Process.

PURPOSE

The Planning Process is intended to develop a regional transmission plan to meet the existing and future requirements of all customers/users, providers, owners, and operators of the transmission system in a coordinated, open and transparent transmission planning environment.

The Planning Process is intended to ensure the long-term reliability of the bulk power system in the FRCC region. However, nothing in this process is intended to limit or override rights or obligations of transmission providers, owners and/or transmission customers/users contained in any rate schedules, tariffs or binding regulatory orders issued by applicable federal, state or local agencies. In the event that a conflict arises between the Planning Process and the rights and obligations included in those rate schedules, tariffs or regulatory orders, and the conflict cannot be mutually resolved among the appropriate transmission providers, owners, or customers/users, any affected party may seek a resolution from the appropriate regulatory agencies or judicial bodies having jurisdiction.

STUDY PROCESS

Studies conducted pursuant to the Planning Process will utilize the applicable reliability standards and criteria of the FRCC and NERC that apply to the Bulk Power System as defined by NERC. Such studies shall also utilize the specific desgn, operating and planning criteria used by FRCC transmission owners/providers to the extent these specific design, operating and planning criteria meet FRCC and NERC reliability standards and criteria or are more stringent than any applicable FRCC and/or NERC standards and criteria.

The 69kV transmission facilities do not fall under the NERC definition of Bulk Power System; however, for the purpose of the Planning Process only, these facilities shall be studied as though they were included in the NERC Bulk Power System definition in order to better coordinate and improve the transmission system in the FRCC Region.

The Planning Process shall begin with the consolidation of the long term transmission plans of all of the transmission owners/providers in the FRCC Region. It is the FRCC's expectation that the long term transmission plans incorporate the integration of new firm resources as well as other firm commitments. This will include all transmission facilities 69 kV and above. Detailed evaluation and analysis of these plans will be conducted by the TWG/SWG, in concert with the FRCC staff, and managed by the Planning Committee. Such evaluation and analysis will provide the basis for possible recommended changes to individual system plans that, if implemented, would result in a more reliable and robust transmission system for the FRCC Region.

The assessment of the long-term transmission plan shall be comprehensive and in-depth. While the final recommended plan may not call for the construction of all transmission facilities identified in various sensitivities, the assessment will provide valuable information on the strength of the transmission system to aid in understanding how the system would perform in various situations. The examination of multiple expected system conditions shall be performed, including an assessment of areas with recurring, significant congestion. As determined by the Planning Committee, these conditions or sensitivities may include any of, but not be limited to, the types listed below:

- Transmission and/or generation facilities unavailable due to scheduled and/or forced outages.
- Weather extremes for summer and winter periods.
- Different load levels (e.g., 100%, 80%, 60%, 40%) and/or periods of the year (Winter, Spring, Summer and Fall).
- Various generation dispatches that will test or stress the transmission system which may include economic dispatch from all generation (firm and non-firm) in the region.
- Reactive supply and demand assessment (e.g. generator reactive limits, power factor, etc.)
- A specific area where a combination/cluster of generation and load serving capability is among various transmission owners/providers in the FRCC that continually experience or is expected in the future to experience significant transmission congestion on their transmission facilities will be reviewed annually and restudied as required. The analysis should reflect the upgrades necessary to integrate new generation resources and/or loads on an aggregate or regional (cluster) basis.

Additionally, such analysis may include an estimate of the cost of congestion as appropriate.

- Other scenarios or system conditions as identified by the Planning Committee (e.g. stability analysis)

For the first 5 years of the planning period, a detailed evaluation will be conducted. For years 6 through 10, a more generalized higher-level study will be conducted.

The Planning Committee shall submit a formal report of the assessment and findings, including any recommendations to the Board. Such report shall include an action plan that identifies:

- Any recommended modifications to transmission owners'/providers' long term plans that, in the judgment of the Planning Committee, offer worthwhile enhancements to regional transmission grid reliability.

- The identification of those elements of the recommended plan that cannot be implemented due to the inability to obtain the required commitments of the affected transmission owner(s)/provider(s) and user(s) to implement the plan.
- The identification of an alternative plan that does have the commitment of the affected transmission owner(s)/provider(s) and user(s) with regard to implementation.
- Any minority views expressed by any member of the Planning Committee as well as the identification of any unresolved issues.

TRANSMISSION PLANNING PROCESS STEPS

A Regional FRCC Transmission Plan ("Regional Plan") shall be developed on an annual basis using the Planning Process. The Regional Plan shall be based on the Ten Year Site Plans that are required to be submitted to the Florida Public Service Commission on April 1st of each year. Any generating or transmission entity not required to submit a ten year plan to the Florida Public Service Commission, shall submit its ten year generation expansion plan to the FRCC on April 1st of each year. These ten year plans shall include the generation expansion plans for load serving entities and firm/network use of transmission submitted by transmission owners/providers.

Step 1– Planning Committee Initiates FRCC Transmission Planning Review and Coordination Process

Transmission owners/providers shall submit to the Planning Committee their latest 10-year expansion plan for their transmission system, including a list of transmission projects that provides for all of their firm obligations based on the best available information. FRCC will post on the FRCC web site the 10-year expansion plans.

Step 2 – Feedback from Transmission Customers/Users/Others of Individual 10-Year Expansion Plan

Transmission customers/users and other affected parties shall submit to the Planning Committee and affected transmission owners/providers any issues or special needs they feel have not been adequately addressed by the applicable transmission owner's/provider's 10-year expansion plan, and the underlying evaluation demonstrating the rationale for their concern.

Step 3 – Review and Assessment by Planning Committee

The Planning Committee shall review and assess transmission owner's/provider's plans from an overall FRCC perspective, ensuring that all affected transmission customers'/users' issues have been identified.

The Planning Committee, the transmission owners/providers and the transmission customers/users shall consult, as appropriate, during this period to address the issues of all parties to ensure their due consideration with regard to possible inclusion into the Regional Plan.

The Planning Committee shall address any issue or area of concern not previously or adequately addressed with emphasis on constructing a robust regional transmission system.

As identified under Information Exchange, the databank used in the development of the Regional Plan will be updated at least quarterly by the TWG. Any changes to the databank that could materially impact the Regional Plan, or affected other parties, will be reviewed by the TWG to determine whether or not the Regional Plan should be revised to reflect those changes.

The Planning Committee shall form working group(s), as necessary, to address specific matter(s) that require further technical assessment or evaluation.

Step 4 – Issuance of Preliminary Regional Plan

The Planning Committee shall issue the preliminary Regional Plan to all FRCC members, and shall identify any proposed modification to the original transmission owner's/provider's plan. The purpose of this step is to receive comments and to identify any remaining unresolved issues.

Step 5 – Approval of Regional Plan

The Planning Committee shall present to the transmission owners/providers, affected transmission customers/users, and other FRCC members a general overview and comments on the Regional Plan, including proposed modifications to each transmission owner's/provider's individual transmission plan.

The Planning Committee shall identify and discuss minority opinions and unresolved issues.

The Planning Committee shall approve the Regional Plan and present it to the Board for its consideration. The Plan may include specific matters that require further technical assessment or evaluation that have been assigned to a working group, and some unresolved issues may still be pending final resolution.

The Board shall take action on the Regional Plan. The resultant Board approved Regional Plan shall be posted on the FRCC public web site and shall be sent to the Florida Public Service Commission.

Step 6 – Unresolved Issues

If any member of the Planning Committee eligible to vote has an unresolved issue(s) after the Planning Committee approves the Regional Plan, said member may direct the Planning Committee to present such unresolved issue(s) to the Board at the same time the Regional Plan is presented for approval.

If the Board fails to satisfy the concerns of the party raising the unresolved issue(s), the party may request the matter be set for Dispute Resolution as set forth in this document. At such time, the FRCC will provide written notice to the Florida Public Service Commission of such unresolved regional reliability issue.

OPENNESS & TRANSPARENCY

It is the intent of the FRCC that the Planning Process be conducted in an open manner in such a way that it ensures fair treatment for all customers/users, owners and operators of the transmission system. This will be accomplished through the process described herein.

Coordination of Transmission Requests

Transmission providers will provide their long-term firm transmission service requests queues and generator interconnection service requests queues to the FRCC in a common format. The FRCC will consolidate all individual queues for coordination purposes and will post the individual queues and the consolidated queue for coordination purposes for all FRCC members to view.

Each transmission provider will furnish the FRCC with a study schedule for each system impact study so that other potentially impacted transmission owners/providers can independently assess whether they may be impacted by the request and determine whether they want to submit a request to the appropriate transmission provider to participate in or monitor the study process. Transmission providers shall allow other transmission owners/providers with potentially impacted transmission facilities to participate in or monitor the study. To the extent there is a question regarding whether a transmission owner's/provider's facilities are impacted, the FRCC will make a determination as to whether the transmission owners'/providers' facilities are impacted. If the study schedules are modified based on discussions with the transmission requestor(s), the updated schedule will also be provided to FRCC.

At the time the system impact study is completed and the study results are presented to the applicable transmission requestor, each transmission provider, in consultation with said requestor, will provide the study results and related models to the FRCC. If the results obtained in the system impact study show that more than one option is recommended for further consideration, the results and related models associated with such options will also be provided to the FRCC.

The FRCC shall make available to all transmission owners/providers, through the TWG, the system impact study schedules and results in order for the TWG, SWG, or any transmission owner/provider to review the system impact studies for any adverse impacts on its system.

The TWG, in concert with the FRCC staff, shall review, and if necessary, perform analyses on the system impact studies to determine if there are any reliability concerns. Such review and analysis shall not delay any regulatory requirements for processing Transmission Service or Generation Interconnection Services requests by the transmission provider. Study results/findings will be made available to the FRCC Planning Committee and the applicable transmission provider for discussion and other action as appropriate.

Public Notice
(Currently under review by the FRCC Standards of Conduct Task Force)

The following process will be followed for any Planning Committee and/or Board meeting in which transmission plans or related study results will be exchanged, discussed or presented:

Meeting Notice
At least two weeks prior to a regular meeting, or 5 business days in the case of a special meeting, the time, place and agenda of that portion of the meeting directly related to discussions of transmission expansion plans or study results will be posted on the FRCC's member web site, as well as each Florida transmission provider's OASIS.

Posting of Documents
Completed FRCC transmission planning studies will be posted on the FRCC's member web site, as well as the OASIS site of any applicable transmission provider(s), subject to possible redaction of user sensitive or critical infrastructure information. A customer/user may enter into a confidentiality agreement with the FRCC and/or applicable transmission owner/provider, as appropriate, to be eligible to review pertinent information relative to the transmission study results subject to critical infrastructure security and market business rules and standards.

Meeting Minutes
Meeting minutes directly related to discussions of transmission expansion plans or study results will be posted as soon as practicable (but no later than one business day) after the end of the meeting on the FRCC's member web site, as well as each Florida transmission provider's OASIS.

INFORMATION EXCHANGE

The FRCC shall maintain a databank of all planned and committed transmission and generation projects, including upgrades, new facilities, and changes to planned in-service dates. This databank shall be updated by the TWG no less frequently than once each quarter and no more frequently than once a month. The frequency of such updates will be determined by the TWG as necessary to ensure that changes that could materially impact the reliability of the transmission system or individual customers/users are reflected in the databank in a timely manner.

The FRCC shall maintain and update the load flow, short circuit and stability models on a quarterly basis, as noted above, utilizing the updated databank to ensure that any changes in transmission or generation projects are reflected in the above models. In the event the databank is updated, such changes will immediately be sent to the TWG and the Planning Committee for their review.

These updated models will be made available to all transmission owners/providers in the TWG and SWG for their individual use and for the TWG's use.

COST ALLOCATION METHODOLOGY AND PRINCIPLES

(Currently under development by the FRCC Cost Sharing Task Force)

DISPUTE RESOLUTION

Any party raising an unresolved issue may request the Mediator Process as described in this document.

If, after the Mediator Process is completed and the issue is still unresolved, by mutual agreement between the parties, the Independent Evaluator Dispute Resolution Process as described in this document will be utilized.

If the unresolved issue involves the inability to reach agreement on the timing or funding of construction of critical transmission facilities required for regional reliability in a timely manner, and such unresolved issue is not resolved by either of the Dispute Resolution Processes described below, the transmission owners/providers, affected parties, or the FRCC may request that the Florida Public Service Commission address such unresolved dispute. Notwithstanding the foregoing, any unresolved issues may be submitted to any regulatory or judicial body having jurisdiction.

Mediator Dispute Resolution Process (Non-Binding)

The Mediator Process shall be completed within sixty (60) days of commencement.

A mediator shall be selected jointly by the disputing parties. The mediator shall (1) be knowledgeable in the subject matter of the dispute, and (2) have no official, financial, or personal conflict of interest with respect to the issues in controversy, unless the interest is fully disclosed in writing to all participants and all participants waive in writing any objection to the interest.

The disputing parties shall attempt in good faith to resolve the dispute in accordance with the procedures and timetable established by the mediator. In furtherance of the mediation efforts, the mediator may:

a. Require the parties to meet for face-to-face discussions, with or without the mediator;

b. Act as an intermediary between the disputing parties;

c. Require the disputing parties to submit written statements of issues and positions; and

d. If requested by the disputing parties, provide a written recommendation on resolution of the dispute.

If a resolution of the dispute is not reached by the 30th day after the appointment of the mediator or such later date as may be agreed to by the parties, the mediator shall promptly provide the disputing parties with a written, confidential, non-binding recommendation on resolution of the dispute, including the mediator's assessment of the merits of the principal positions being advanced by each of the disputing parties. At a time and place specified by the mediator after delivery of the foregoing recommendation, but no later than 15 days after issuance of the mediator's recommendation, the disputing parties shall meet in a good faith attempt to resolve the dispute in light of the mediator's recommendation. Each disputing party shall be represented at the meeting by a person with authority to settle the dispute, along with such other persons as each disputing party shall deem appropriate. If the disputing parties are unable to resolve the dispute at or in connection with this meeting, then: (1) any disputing party may commence such arbitral, judicial, regulatory or other proceedings as may be appropriate; and (2) the recommendation of the mediator shall have no further force or effect, and shall not be admissible for any purpose, in any subsequent arbitral, administrative, judicial, or other proceeding.

The costs of the time, expenses, and other charges of the mediator and of the mediation process shall be borne by the parties to the dispute, with each side in a mediated matter bearing one-half of such costs. Each party shall bear its own costs and attorney's fees incurred in connection with any mediation under this Agreement.

<u>Independent Evaluator Dispute Resolution Process (Non-Binding)</u>

The Independent Evaluator Dispute Resolution Process shall be completed within ninety (90) days.

- An assessment of the unresolved issue(s) shall be performed by an Independent Evaluator that will be selected by the Board. The Independent Evaluator shall evaluate the disputed issue(s) utilizing the same criteria that the Planning Committee is held to; that is, "the applicable reliability criteria of FRCC and NERC, and the individual transmission owner's/provider's specific design, operating and planning criteria".

- The Independent Evaluator shall be a recognized independent expert with substantial experience in the field of transmission planning; with no past business relationship to any of the affected parties within the past two years from the date the Dispute Resolution Process is started. A list of qualified experts should be pre-established so that when an issue arises the Board can expedite the process.

- The Board shall retain an Independent Evaluator within fifteen (15) days of the request to utilize the Independent Evaluator Dispute Resolution Process.

- The Independent Evaluator shall prepare a report of its findings, with recommendations on the unresolved issue(s), to the Board and the Planning Committee within forty-five (45) days from the date the Board selected the Independent Evaluator. The Independent Evaluator's findings and recommendations shall not be binding. The Board, with the assistance of the Planning Committee and the Independent Evaluator's report, shall attempt to resolve the unresolved issue(s) within thirty (30) days from receipt of the Independent Evaluator's report. If the Board fails to resolve the issue(s) to the satisfaction of all parties, any disputing party may commence such arbitral, judicial, regulatory or other proceedings as may be appropriate.

- The costs of the Independent Evaluator shall be borne by the parties to the dispute with each party bearing an equal share of such costs. The FRCC shall be one of the parties. Each party shall bear its own costs and attorney fees incurred in connection with the dispute resolution.

C

2007 - 2016
Long Range Transmission Study
Executive Summary

FLORIDA RELIABILITY COORDINATING COUNCIL

Approved by Planning Committee
July 12, 2007

Executive Summary

2007 – 2016 Long Range Transmission Study

PURPOSE STATEMENT

The 2007 – 2016 Long Range Transmission Study (STUDY) is performed by the Florida Reliability Coordinating Council (FRCC) Transmission Working Group (TWG) to provide the information needed for its members and staff to assess the compliance of the FRCC transmission system with the requirements set forth in the North American Electric Reliability Corporation (NERC) Reliability Standards. These reliability standards include the following Transmission Planning Standards (see Attachment A): System Performance Under Normal Conditions (TPL-001-0); System Performance Following Loss of a Single Bulk Electric System Element (TPL-002-0); and System Performance Following Loss Two or More Bulk Electric System Elements (TPL-003-0). These standards provide the transmission owners with a set of performance requirements for the planning of the transmission system throughout the ten-year planning horizon.

This summary will communicate the assumptions, methodology, results and observations of the STUDY to the FRCC Planning Committee (PC) and other interested parties. This summary serves as a general review of the performance of the transmission system and planned transmission expansion within the FRCC Region.

INTRODUCTION

The STUDY is a steady-state assessment of the adequacy of the FRCC's bulk and 69 kV transmission system for 2007 through 2016. The nature of this study, being steady-state, addresses both thermal and voltage conditions. Furthermore, NERC Transmission Planning Standards are used to gauge the adequacy of the transmission system. In general, these transmission planning standards state that the transmission system will remain stable, within the applicable thermal and voltage rating limits, without cascading outages; under normal system conditions, as well as single and multiple contingency events.

The STUDY is conducted in two parts. Part I, representative of the first five years, is analyzed in detail with specific remedies identified for all thermal or voltage screening criteria violations. Part II, representative of the second five years, is also reviewed to determine if any trends are developing that would require attention. This is done to acknowledge the greater confidence in the transmission owner's short-term capital improvement plans. The STUDY includes normal conditions (Category A) and single contingency analysis (Category B) which outages and monitors all transmission facilities rated 69 kV and above and identifies any elements that perform outside the screening criteria. In addition, this STUDY also includes outages of two or more bulk transmission system elements identified as follows: breaker failure events (Category C2); loss of two independent facilities (Category C3); loss of any two circuits of a multiple circuit tower line (Category C5).

ASSUMPTIONS

- Steady-state peak load conditions for the summer 2008, 2009, 2010, 2011, 2013 and winter 2009/10, 2012/13 seasons as represented in the FRCC FY06 load flow databank cases.
- All transmission facilities and generating units are available in the base cases.
- Thermal screening limit is 100% of Rate A for Category A conditions and 100% of Rate B for Category B and Category C events.
- The general criteria used to screen under/over voltage conditions are 95% and 105% of nominal; individual transmission owner voltage criteria may be less than 95%.
- Thermal and voltage screening criteria applies to all transmission facilities 69 kV and above.
- Contracted firm (non-recallable) transmission services are reflected in the models.
- For all manual load tap changing transformers, the taps are locked to simulate post event conditions prior to operator intervention.
- Generators are forced to control the voltage of the low-side bus.

METHODOLOGY

The STUDY covers a ten-year horizon: the first five years (represented by 2008, 2009, 2010, 2011 Summers and 2009/10 Winter), and the second five years (represented by 2012/13 Winter and 2013 Summer). The ten-year horizon contains information of different confidence levels and the accepted remedial action requirements are viewed differently as explained below.

The major assumptions used in the STUDY are the forecasted load serving entities' seasonal peak loads, planned generation additions, planned transmission improvements, and firm transmission service. The confidence level of these major assumptions decreases as time progresses. The information contained in the models representing the first five years is comprised of committed projects with a high degree of confidence. The uncertainty of the major assumptions grows through time within the second five years. Generation plans may not be firm and the location of future generation may be unknown. Many transmission infrastructure projects in the planning stages are not represented in the models. This results in a conservative, rather than an overly optimistic, analysis.

The transmission and generation expansion plans for the first five years have a high degree of certainty; therefore operator intervention remedial actions for thermal and/or voltage screening criteria violations are restricted to available actions such as line switching, changing generation dispatch, transformer tap changing and capacitor switching.

The second five years provide sufficient lead time for uncommitted planned projects to be budgeted and built; therefore, identification of specific operator remedial actions is not required. The preliminary addition of planned projects and the plan to study solutions can be acceptable remedies for the second five years.

Transmission Planning Standards TPL-001-0, TPL-002-0 and TPL-003-0 state that the transmission system will remain stable, within the applicable thermal ratings and voltage criteria, without cascading outages and with some controlled loss of demand or curtailment of firm power transfers during Category A conditions and after Category B and C events for the time period specified.

Category A Analysis

For Category A conditions, all transmission facilities rated 69 kV and above are monitored and compared to the applicable thermal rating and/or voltage screening criteria throughout all study cases. Any facility loadings exceeding the equipment thermal rating and/or voltage screening criteria are reviewed by the transmission owners and the corrections or resolutions provided by the transmission owners are reflected in the base cases for the remainder of the analyses.

Category B Analysis

For Category B, all transmission facilities rated 69 kV and above are singularly removed from service throughout all study cases. Contingencies resulting in branch loadings exceeding thermal ratings and/or voltage screening criteria are reviewed by the transmission owners. Remedies are then provided by the transmission owners to resolve potential screening criteria violations.

Category C2 Analysis

Breaker failure events (Category C2) that result in the loss of two or more transmission system elements 230 kV and above that exceed the thermal and/or voltage screening criteria are reviewed by the transmission owners. Remedies are provided by transmission owners to resolve potential screening criteria violations.

Category C3 (lines) Analysis

The 2009 summer season FRCC load flow databank case was used to evaluate multiple contingency events (Category C3 - lines) that result in the loss of two independent transmission elements. PTI's MUST software was used to perform this evaluation on a zone by zone basis to accommodate software limitations. All combination of lines 100 kV and above were evaluated sequentially within each zone. Results showing line loadings greater than 130% or bus voltages less than 0.90 per unit were identified as candidates for further evaluation. Candidate double contingencies that did not exceed thermal and/or voltage screening criteria when evaluated as single contingencies required a remedy by the transmission owner for the double contingency. Remaining candidate double contingencies that exceed thermal and/or voltage screening criteria, when evaluated as single contingencies, are modeled individually with the necessary system reconfiguration prior to the subsequent contingency. The results of the double contingencies with the system are reviewed by the transmission owners and remedies are developed to address any resultant thermal and/or voltage potential screening criteria violations.

This is the first time the TWG has performed this type of analysis in the long range assessment. The potential number of combinations of matched pairs (over 900,000) even when restricted to geographic areas can be over 90,000. The process was developed to comply with TPL-003-0 and replicate system operator actions in the event of an initial outage followed by a second outage. In order to perform this analysis, the FRCC Region was divided into geographical zones and the independent outages were restricted to the individual zones. Paired outages that resulted in thermal loadings greater than 130% and/or voltages less than 90% were screened to be studied in more detail as described above.

Category C3 (generators) Analysis

FRCC load flow databank cases representing the summer 2009, summer 2013, winter 2009/10 and winter 2012/13 peak seasonal conditions were used to evaluate multiple contingency events (Category C3 - generators) that result in the loss of one generating unit followed by changes in dispatch and the subsequent loss of one transmission element. All combinations of elements rated 69 kV and above are paired with the loss of either Crystal River #3, St. Lucie #1 or the steam portion of the Ft. Myers unit for evaluation. Events that exceed the thermal and/or voltage screening criteria were reviewed by the transmission owners. The individual transmission owners provide remedies for the resolution of these potential screening criteria violations.

Category C5 Analysis

Multiple contingency events (Category C5) involve the loss of two circuits of a multiple circuit towerline greater than one mile in length and rated 230 kV and above. Contingency events exceeding the thermal and/or voltage screening criteria are reviewed by the transmission owners. Remedies are provided by transmission owners to resolve potential screening criteria violations.

Coordinated Remedies

Coordinated remedies are required when multiple transmission owners are affected. Near the boundaries between two or more transmission owners, contingencies which result in thermal loading and/or voltage screening criteria violations require coordinated remedies. The transmission owners discuss various options, including coordinated generation redispatch, in order to develop coordinated remedies that address the transmission concerns.

RESULTS

The results of this STUDY for normal, single and multiple contingency events within the FRCC Region meet NERC Transmission Planning Standards and the FRCC Planning Process. Although the NERC Transmission Planning Standards apply to the bulk power system (100 kV and above), the FRCC Region also applies Transmission Planning Standards TPL-001-0 and TPL-002-0 to 69 kV transmission facilities. The results of this study are discussed in two parts.

Part I, representative of the first five years of the STUDY, includes transmission system performance under Category A conditions, Category B and Category C events. For Category A conditions and Category B and Category C events, the performance of the transmission system was shown to be adequate and in compliance with NERC Transmission Planning Standards supported by documentation provided by the individual transmission owners. The results of the STUDY provided valuable transmission system information (see observation section below).

The results of Part II, representative of the second five years of the STUDY, includes transmission system performance under Category A conditions, Category B and Category C events. The transmission system is evaluated to identify possible emerging concerns, monitor known concerns, monitor the effects of planned projects and identify major projects that may require long lead times. The remedies developed for this section take into consideration the uncertainty of the generation expansion plan and the location and timing of projected loads. In addition, the transmission expansion plans representing the second five years of this study are typically under review by most transmission owners still considering multiple alternatives for each project. Therefore, since specific transmission projects have not been identified or committed to by most transmission owners, these projects are not incorporated into the load flow models. The results show local loading trends throughout the FRCC Region as expected given the uncertainties discussed above. No major projects requiring long lead times were identified. In addition, the results of Part II of this study show significant improvements throughout the Central Florida area due to the implementation of the planned and committed projects in this area.

OBSERVATIONS

Based upon a review of the study results, some observations can be made as to the performance of the power system under Category C3 (lines) events. In general, the possible results of these events can be mitigated by adjusting the power system to be ready for the next event in order to fully comply with NERC Transmission Planning Standards. These observations lead to the identification of five areas that may require further evaluation to understand the underlying assumptions related to study results and trends in the study horizon. The areas are as follows:

1. Polk / Hardee generation area and the load in the Greater Orlando area
2. Northwest Florida
3. Avon Park / Ft. Meade
4. Manatee / Ringling / Laurelwood
5. Northeast Florida area surrounding Jacksonville

Polk/Hardee generation area and the load in the Greater Orlando area

This STUDY included the projects and operational actions identified in the latest Florida Central Coordinated Study (FCCS). This STUDY found that the FCCS projects and operational actions continue to be effective.

The FCCS study was a comprehensive study that covered a specific area of Florida (Polk/Hardee generation area and the load in the Greater Orlando area). The study was completed in 2006 and identified several major 230 kV projects that need to be constructed and in service as soon as possible. Work has begun on these 230 kV projects to correct the system constraints, and the majority of the projects will be in service by June 2011. Based on these projects, planned generation additions and firm system dispatch, it is expected that operational actions will continue to be required in this area until 2011. These operational actions have been developed jointly between transmission owners and are evaluated regularly to ensure system reliability and effectiveness. This area is sensitive to higher than expected loads, non-firm generation, dispatch and extended generation outages, all of which are considered in the development of the operational actions. There will be additional FRCC studies covering this area to insure that the planned projects continue to be sufficient and to plan for the years beyond 2012 based on forecasted growth.

Northwest Florida area

The Tallahassee (TAL) and Progress Energy of Florida (PEF) transmission systems are tightly interconnected and contingencies on either system may affect elements on the other. For Category B, there are two single contingency events, one on the TAL system and one on the PEF system that result in overloads respectively on the other's system. Both of these potential screening criteria violations can be resolved by multiple transmission owner coordination and the sectionalizing of transmission lines.

On the TAL system, one C2 and three C5 contingency events resulted in overloads. The C5 contingency events can be resolved with local area load shedding. The C2 contingency event can be resolved by sectionalizing. One C5 contingency event is notable in that the loading is 158% and requires approximately 150MW of load shedding to resolve. For this contingency event, an automatic load shedding scheme is being implemented to reduce the loading to 130% starting in summer 2007. For the C5 contingency events, projects are planned and documented (rebuild or reconductor). A long term solution to the C2 contingency event will be addressed in a future joint study.

Outside of the Tallahassee area, the Northwest Florida area has a majority of 69 kV and 115 kV lines of small capacity (primarily built in the 1950's and 1960's) that serve large areas of widely dispersed, relatively low-density loads. Many of these lines have been slowly approaching their capacity limits over the years and are very sensitive to load variations as seen in the Category B and Category C results. This area's sparse transmission topography and vast geography (stretched over 200 miles) limits the availability of additional area support. Many of the remedies to resolve Category B and Category C events in this area include the possibility of local area load shedding.

The area around Tallahassee has a number of issues that are to be addressed by separate studies. Currently, the 'Scholz Area Study' with Southern Company and interested FRCC members is underway to address the affects of specific changes on Southern's system on this area. These changes were identified in the results of a higher level study which was recently reported to the Southern-Florida Interface Planning Committee at their Spring 2007 meeting. Immediately following completion of the 'Scholz Area Study', another long range planning study of the Northwest Florida area with interested FRCC members will be performed to focus on the remaining issues around Tallahassee that do not specifically relate to Southern Company.

Avon Park / Ft. Meade area

The Avon Park / Ft. Meade area had Category B and Category C3 events reported that exceeded the screening criteria. These events were primarily due to contingencies which will be resolved by the Avon Park – Ft. Meade 115 kV to 230 kV conversion project scheduled for completion by

Summer 2009. Remedies to maintain compliance with the Transmission Planning Standards have been identified and documented which will support this area prior to the completion of this project.

Manatee / Ringling / Laurelwood area

Category C2 and Category C3 analyses in the Manatee / Ringling / Laurelwood area produced results which identified contingency events resulting in line loadings in excess of 140%. The area is generally in the path from the Manatee plant southward toward Charlotte.

The normal flow pattern is north to south with load being served along the way.
The Ringling – Laurelwood 138 kV area is fed from the 230 kV system more inland and east of these 138 kV lines via the Ringling, Laurelwood, and Howard 230/138 kV autotransformers. The Category C3 contingency events which remove both 230 kV feeds to the Howard autotransformers results in thermal overloads on the 138 kV lines from Ringling and Laurelwood.

FPL is evaluating the most effective long term remedy to address this condition. The near term remedy to manage these overloads is for the operator to shed load in the area. FPL is currently evaluating the response time and the amount of load shedding required to adequately relieve the overloaded lines. An automatic load shedding scheme coordinated with the loss of the 230 kV sources to Howard is being considered.

The Category C2 event at Ringling which removes the 230 kV feed to the Howard autotransformer could be resolved with either an automatic load shedding scheme or the reconfiguration of the lines within the Ringling Substation. Both options are currently being evaluated.

Northeast Florida area

Under certain generation dispatch and system load levels, the Northeast Florida area surrounding Jacksonville is exposed to Category C3 events that require locally controlled load shedding. The amount of load that would be shed in order to reduce thermal loadings to within each facility's normal rating is no more than 400 MW for the worst case Category C3 event occurring at forecasted peak load levels. The amount of load shedding for Category C3 events can be minimized by opening a 138 kV transmission tie line. This action results in no adverse affects on neighboring systems.

Reductions in flows through JEA's system due to planned additions of generation and transmission system improvements external to JEA will decrease the amount of load shedding required to maintain thermal loadings on affected transmission elements as well as system voltage within criteria.

CONCLUSION

The STUDY for the FRCC Region concludes that potential thermal and voltage screening criteria violations can be resolved by operator intervention meeting NERC Transmission Planning Standards. These resolutions were thoroughly reviewed by the transmission owners and found to be adequate in order to maintain acceptable system performance under Category A conditions, Category B and Category C events.

The FRCC Region load is expected to continue to grow throughout the study horizon. This continued growth is being addressed by additional transmission investment within the FRCC Region. See Attachment B for detailed information on the planned transmission investments.

Attachment A

A. Introduction

1. **Title:** **System Performance Under Normal (No Contingency) Conditions (Category A)**

2. **Number:** TPL-001-0

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table 1. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-001-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon.

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-001-0_R2.1 and TPL-001-0_R2.2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard TPL-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Compliance Monitor: Regional Reliability Organization.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe
Annually

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	June 03, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B)**
2. **Number:** TPL-002-0
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.
4. **Applicability:**
   - **4.1.** Planning Authority
   - **4.2.** Transmission Planner
5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories,, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

D[d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 3. Transformer 2. Transmission Circuit 4. Bus Section - - - - - - - - - - 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) - - - - - - - - - - 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

A. Introduction

1. **Title:** **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)**
2. **Number:** TPL-003-0
3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements, with sufficient lead time and continue to be modified or upgraded as necessary to meet present and future System needs.
4. **Applicability:**
   - **4.1.** Planning Authority
   - **4.2.** Transmission Planner
5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that System performance meets Table 1 for Category C contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C.

R1.5. Consider all contingencies applicable to Category C.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-003-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective NERC Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-003-0_R1 and TPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-003-0_R3.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Monitoring Responsibility**

   Compliance Monitor: Regional Reliability Organizations.

   1.2. **Compliance Monitoring Period and Reset Timeframe**

   Annually.

   1.3. **Data Retention**

   None specified.

   1.4. **Additional Compliance Information**

   None.

2. **Levels of Non-Compliance**

   2.1. **Level 1:** Not applicable.

   2.2. **Level 2:** A valid assessment and corrective plan for the longer-term planning horizon is not available.

   2.3. **Level 3:** Not applicable.

   2.4. **Level 4:** A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	April 1, 2005	Add parenthesis to item "e" on page 8.	Errata

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	 Yes Yes Yes Yes	 No [b] No [b] No [b] No [b]	 No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	 Yes Yes Yes Yes	 Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	 No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Attachment B

PLANNED TRANSMISSION INVESTMENT

There continues to be significant investment in the transmission system within FRCC. In summary, the major activities for the next 5 years include:

	230 kV				138 kV				115 kV			
Company	New	Miles	Rebuild	Miles	New	Miles	Rebuild	Miles	New	Miles	Rebuild	Miles
FPL	31	289	1	5	13	54	15	61	5	25	15	90
PEF	25	279	8	75	0	0	0	0	27	125	6	24
JEA	11	53	0	0	2	5	0	0	0	0	0	0
OUC	5	15	0	0	0	0	0	0	0	0	0	0
SECI	0	0	0	0	4	21	0	0	5	21	0	0
TAL	0	0	0	0	0	0	0	0	9	53	4	23
TECO	5	64	0	0	1	6	0	0	0	0	0	0
FMPA	2	6	0	0	0	0	0	0	0	0	0	0
HST	0	0	0	0	2	5	0	0	0	0	0	0
OEU	1	13	0	0	0	0	0	0	0	0	0	0
TOTAL	**80**	**719**	**9**	**80**	**22**	**91**	**15**	**61**	**46**	**224**	**25**	**137**

In addition, there are many 69 kV line and substation projects that are being constructed to serve load growth and resolve potential screening criteria violations on the 69 kV transmission system.

D

TRANSFER CAPABILITY STUDY: FLORIDA / SOUTHERN INTERFACE

For 2007 Bulk Electric Supply Conditions

Final Report
August 30th, 2006

TRANSFER CAPABILITY STUDY:
FLORIDA / SOUTHERN INTERFACE

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APPENDICES

SUMMARY

The Total Transfer Capabilities (TTC[1]) between the FRCC Region (Florida) and the Southern Control Area within the SERC region (Southern) as determined by this study are given below. A more detailed summary of TTC results is given in Appendix A. It is recommended that the values shown in Table 1 be reported to NERC for their upcoming Seasonal Assessment Reports and for OASIS postings of the Florida/Southern Interface Available Transfer Capability (ATC) and TTC values for these time periods. The 2007 summer transfer capabilities are representative of the June through September 2007 time period and the 2007/2008 winter transfer capabilities are representative of the December 2007 through February 2008 time period. Note that various operating procedures are required to achieve these results. Information regarding these operating procedures is contained later in the report and in the appendices.

TABLE 1	**TTC (MW)**	
Season	**SOU to Fla**	**Fla to SOU**
2007 Summer	3600	1500
2007/2008 Winter	3700	2000

Interpolated TTC values for the off peak spring and fall periods are shown in Table 2 to assist Operations in the OASIS postings of the Florida/Southern Interface Available Transfer Capability (ATC) and TTC values for these time periods. The spring values are representative of the March through May period and the fall values are representative of the October through November period.

TABLE 2	**TTC (MW)**	
Season	**SOU to Fla**	**Fla to SOU**
2007 Spring	3600	1700
2007 Fall	3600	1700

[1] Total Transfer Capability, Available Transfer Capability Definitions and Determination, NERC Publication, June 1996

INTRODUCTION

This analysis was conducted at the request of the Southern/Florida Planning Committee. The purpose of the study is to determine the TTC values between the FRCC and the Southern subregion of SERC for the 2007 summer and 2007/2008 winter time periods. Transfers were evaluated based on the methodologies and criteria of the importing utilities.

Southern models are based on the latest available 2006 series base cases. The FRCC models are based on the 2006 FRCC data bank. Loadflow assessments of the Florida and Southern systems were performed using criteria and methodology consistent with NERC guidelines/standards and those reported to FERC in the FERC 715 filings. A list of the tested transmission contingencies is provided in Table 3. Some contingencies cause overloads or voltage problems that are not significantly related to transfers between Southern and Florida. These overloads can be resolved by operating procedures (primarily switching of transmission lines) which were reviewed and approved by the impacted transmission system owners. The operating procedures examined in this study are listed in Appendix B.

In the summer and winter seasons it was necessary to reduce load in the exporting systems for Florida to Southern transfers in order to achieve transfer test levels high enough to find a limitation to transfers. Importing utilities maintain their peak load during these transfers. The load in the FRCC region was reduced to 90% of the seasonal peak to evaluate Florida to Southern transfers for both seasons. Import transfer studies for Southern modeled a critical unit to the interface as off line and unavailable. For summer and winter transfers from Florida, the critical unit out modeled was Vogtle #1.

With power transfers at or close to the TTC level, there are some contingencies that cause overloads. Overloaded facilities that do not respond to transfers (facilities with transfer distribution factors lower than 3% and not likely to cause widespread or cascading outages) were not considered limitations to transfers. Additionally, there are some transfer limiting overloads that can be resolved with operating procedures, and they are listed in Appendix B.

SOUTHERN TO FLORIDA TRANSFERS

2007 Summer Period

The TTC was found to be 3600 MW for the 2007 summer conditions which is the same as reported for the 2006 summer period. At transfers higher than 3600 MW, the outage of the Martin #1 generator results in nonconvergence due to reactive power limitations.

2007/2008 Winter Period

The TTC was found to be 3700 MW for 2007/2008 winter conditions which is the same as the reported value for the previous 2006/2007 winter period. At transfers higher than 3700 MW, the outage of the Turkey Point (#3 or #4) generator results in nonconvergence due to the reactive power limitations.

FLORIDA TO SOUTHERN TRANSFERS

2007 Summer Period

The TTC was found to be 1500 MW for the 2007 summer conditions which is 200 MW higher than reported in the last joint study report for the 2006 summer Florida to Southern transfer capability. The Crystal River – Bronson 230 kV circuit is at its normal summer rating of 492 MVA without contingencies at the 1500 MW test transfer level and exceeds its rating at higher transfers.

2007/2008 Winter Period

The TTC was found to be 2000 MW for 2007/2008 winter conditions which is 300 MW higher than reported in the last joint study report for the 2006/2007 winter period. The outage of the Crystal River – Brookridge 500 kV line causes the Central Florida 500/230 kV autotransformer banks to exceed their B rating of 825 MVA. The reason for the increase from last year's reported value is due to an increase of dispatched generation in the Savannah, Georgia area of the Southern Control Area.

Table 3 - Contingency List

500 kV lines
- Bonaire to Hatch
- Duval to Hatch
- Duval to Thalmann
- Farley to Snowdoun
- Farley to Raccoon Creek
- North Tifton to Raccoon Creek
- Fortson to N. Tifton
- Thalmann to McCall Road
- McCall Road to West McIntosh
- Vogtle to West McIntosh
- Crystal River to Brookridge
- Crystal River to Central Florida
- Poinsett to Rice
- Poinsett to Martin
- Poinsett to Midway

500/230 kV Transformers
- Farley #1
- North Tifton
- Poinsett
- Raccoon Creek
- Thalmann
- West McIntosh #1
- West McIntosh #2

230 kV lines
- West Brunswick to Thalmann
- Colerain to Thalmann
- Colerain to Kingsland
- SOWEGA to Albany
- Raccoon Creek to Mitchell
- Raccoon Creek to SOWEGA
- Raccoon Creek to North Camilla

230 kV lines (continued)
- S. Bainbridge to Sinai Cemetery
- Lansing Smith to Callaway
- Lansing Smith to Sinai Cemetery
- Farley to South Bainbridge
- Farley to Sinai Cemetery
- Farley to Cotton Wood
- North Tifton to Pinegrove
- Kingsland to Yulee
- Hatch to Eastman Primary
- Pinegrove to Sterling
- Sterling to Suwannee
- Bonaire to Dorsett
- East Moultrie to West Valdosta
- North Tifton to East Moultrie
- S. Bainbridge to Sub #20
- Callaway to Port St. Joe
- Duval to Springbank
- Greenland to Switzerland
- Ft. White to Newberry
- Ft. White to Ginnie
- Ft. White to Suwannee
- Normandy to Brandy Branch
- Brevard to Sarno
- Malabar to Hield

115 kV lines
- Scholz to Woodruff

Generating Units
- Crystal River #3
- Manatee #1
- Martin #1
- St. Lucie #2
- Turkey Point #4
- Vogtle #1

Appendix A
Total Transfer Capabilities

TTC SUMMARY				
Transfers	**Scenario**	**TTC**	**Limiting Contingency**	**Limiting Facilities (see notes)**
Sou to Fla	2007 Summer	3600 MW	Martin #1 generator outage	Non-Convergent (4,5)
Sou to Fla	2007/2008 Winter	3700 MW	Turkey Point #3 or #4 generator outage	Non-Convergent (4,5)
Fla to Sou	2007 Summer	1500 MW	None (base case overload)	Crystal River – Bronson 230 kV (492 MVA rating) (1, 2, 3, 5)
Fla to Sou	2007/2008 Winter	2000 MW	Crystal River – Brookridge 500 kV	Central Florida – 500/230 kV Transformers Rate B, 825 MVA (1,2, 3, 5)

1. Overloads at transfers higher than TTC
2. Fully loaded at transfer test level (≥99% loaded)
3. Florida area load at 90% of seasonal peak
4. Non-convergence due to reactive power limitations at transfers higher than TTC
5. Operating procedure in effect

Appendix B
Operating Procedures

Southern to Florida Transfers Greater than 3500 MW 2007 Summer Operating Procedures		
Contingency	**Overload Facility**	**Southern Operating Procedure**
None (precontingency)	Pinegrove - Jasper 115 kV	Open: Pinegrove - Jasper 115 kV
Contingency	**Overload Facility**	**Florida Operating Procedure**
S. Bainbridge-Sub #20 230 kV	Woodruff – River Junct. 115 kV	Open: Bradfordville – Havana 115 kV
Greenland – Switzerland 230 kV	Center Park – Neptune 138 kV	Close: N.O. bus breakers at Seminole

Florida to Southern Transfers Greater than ~100 MW (1) 2007 Summer Operating Procedures		
Contingency	**Overload Facility**	**Southern Operating Procedure**
None (precontingency)	Pinegrove - Jasper 115 kV	Open: Pinegrove - Jasper 115 kV
Contingency	**Overload Facility**	**Florida Operating Procedure**
None (precontingency)	Ft. White 115/69 kV transformer	Split Ft. White 69 kV bus
None (precontingency)	Martin W. - Reddick 69 kV	Open: Reddick – Proctor Tap 69 kV
Crystal River – Cen.Fla. 500 kV	L.Agnes – Osceola 230 kV	Open: L. Agnes reactor bypass switch
Ft. White - Suwannee 230 kV	L.Agnes – Osceola 230 kV	Open: L. Agnes reactor bypass switch
Ft. White - Newberry 230 kV	L.Agnes – Osceola 230 kV Santos – Tmbrwdtp 69 kV	Open: L. Agnes reactor bypass switch Open: Silver Springs – Santos 69 kV
None (precontingency)	Trenton - High Springs 69 kV	Open: Trenton - Bell Tap 69 kV
None (precontingency)	Inglis - Trenton 69 kV	Open: Georgia Pa. - Usher Tap 69 kV

(1) Some operating procedures may not be needed depending upon the level of Florida Export

Southern to Florida Transfers Greater than 3500 MW 2007/2008 Winter Operating Procedures		
Contingency	**Overload Facility**	**Southern Operating Procedure**
None (precontingency)	Pinegrove-Jasper 115 kV	Open: Pinegrove-Jasper 115 kV
Contingency	**Overload Facility**	**Florida Operating Procedure**
S. Bainbridge-Sub #20 230 kV	Woodruff – River Junct. 115 kV	Open: Bradfordville – Havana 115 kV
Greenland – Switzerland 230 kV	Center Park – Neptune 138 kV	Close: N.O. bus breakers at Seminole

Florida to Southern Transfers Greater than ~100 MW (1) 2007/2008 Winter Operating Procedures		
Contingency	**Overload Facility**	**Southern Operating Procedure**
None	None	None
Contingency	**Overload Facility**	**Florida Operating Procedure**
None (precontingency)	Ft. White 115/69 kV transformer	Split Ft. White 69 kV bus
None (precontingency)	Martin W. - Reddick 69 kV	Open: Reddick – Proctor Tap 69 kV
None (precontingency)	Trenton - High Springs 69 kV	Open: Trenton - Bell Tap 69 kV

(1) Some operating procedures may not be needed depending upon the level of Florida Export

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