U.S. Department of Energy
Pre-Congestion Study Regional Workshops for the 2009 National Electric Congestion Study

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9:00 a.m.-12:30 p.m.

Transcript

David Meyer: Ladies and gentlemen, I'm David Meyer from the Department of Energy. I want to welcome you to our workshop for upcoming 2009 congestion studies. I'm going to make a short presentation here scoping out what we have in mind and what our purposes are in holding this workshop.

But, before I do that, I want to introduce some of my colleagues here, particularly Lot Cooke who is from our General Counsel's office. Several other people from my office at the Department of Energy: Mark Whitenton and Elliott Nethercutt; and Elizabeth Mortenson is helping with the registration. And so if have questions that you want to discuss with us while we're here, any one of those folks can help you. Also, we have Joe Eto from Lawrence Berkeley Laboratories. Many of you know Joe from various previous projects that you may have worked with him on.

So, now, let's turn now to our plan for the congestion study. The Energy Policy Act of 2005 directs us to publish a congestion study every three years. And we did the first one in August of 2006, so the next one is August 2009. We are hosting six of these workshops in various cities. And this is the fourth meeting. We have one coming up in Las Vegas next week. And then we've got one in Chicago for the JM footprint in mid-September.

In addition, we are maintaining an open-door policy while we're doing this study. That is, anyone who wants to come and talk with us about congestion matters we would be very happy to do that. And, you just have to give us a call, and we can set up a face-to-face meeting or a conference call or we'll work something out one way or another.

So, can we go to the next slide? The Energy Policy Act authorizes the designation of National Corridors. But we want to emphasize that the workshops that we're talking about here and the upcoming study is a congestion study. This does not necessarily have connections to the designation of additional corridors. That-- whether additional corridors are designated that's going to depend to a great extent on our incoming management team, and of course, at this point it's just not possible to say, you know, what their views are going to be with respect to possible new corridors.

So, can we go to the next slide? So, we're holding these workshops to tell people what we have in mind for the upcoming 2009 study and to get suggestions from people, stakeholders about what publicly available data that we should focus on and we do that to the maximum extent possible. We do want to rely on publicly available data. Because we want the study to be as transparent as we can make it. And then so there are questions about how we can evaluate that data or other kinds of information.

So we welcome your suggestions not just about data, but a lot of times there are regional studies or sometimes company-level studies that are especially valuable, and so we ask you-- if you know of such materials that we should be reviewing, please-- indicate them to us.

This congestion study will focus on recent or current congestion. That is, it will, not unlike the 2006 study, we do not expect to do projections. The last time around we did do projections of congestion. We did our own modeling for the eastern interconnection and then we worked with an ad hoc group of folks under the offices of WECC to do projections in the West. And we still will to work with the same group or a successor group in the West, but it's going to be an historical review or a review using current data. And, then we will engage-- or have engaged a contractor OATI, Open Access Technologies International, to work with us on the eastern interconnection.

The-- A reminder that the Energy Policy Act exempts ERCOT from these congestion study requirements but we will focus, as we did before, on-- between interconnections separately. Today we will have different panels. And in each case I will ask each of the panelists to make a brief statement. Their perspectives on congestion issues. And then we will move from there on into discussion some salient questions, and I will identify those questions and moderate the discussion.

There will be an opportunity at the close of the workshop for those of you in the audience who-- it's not possible to put everyone on the panel who might want to be on the panel, so if you want to make a statement to us, there will be a period for you to do that, and we certainly invite anyone who wants to make statements at that time to please come forward.

And finally, we-- the dialogue that goes on here today will be important. And we will have a transcript made just so that we can go back and identify specific suggestions that were made, and so on, and then follow up on them. We urge everyone to submit written materials to us, because then you can do that in whatever length you want.

Or, if you want to send us existing documents, you can do that. But it is important, if possible, to send these materials electronically, because regular mail-- for security reasons now, ever since the anthrax problem, incoming mail at that time gets put through a process that frequently damages the written stuff. And so, at a minimum it arrives about three weeks after you think it would. And secondly, it may not be readable when it gets there. So, it's very important to send it to us electronically. If you want to also send a hard copy fine, but the electronic stuff is important.

Our 2006 study identified several areas in the country that were of concern from a congestion point of view, and we invite panelists to bring us up-to-date on those trends in those areas, or if there were-- are new areas of concern that your-- things that have-- problems that have surfaced in one way or another since 2006, please tell us.

This is a rough schedule. That is, we ask people who are going to supply materials to us, to if possible, supply those to us by October 15. Not that the window is going to slam shut on October 15, but it will start to close, and at some point, probably after the first of the year, we simply will have to say, okay, the window's closed. We now have to absorb and synthesize the material that we have received.

So, January to March would be to develop and outline the report and analyze the data. Actually, the analysis will start much sooner than that, but we have to wrap that up in that period. And then, April-May we will be drafting the report, and then in June we go into a clearance process, aiming at publication in August.

And so here is our web address again, and any comment-- I should add that any comments, any materials that you send us will be posted on the website unless, of course, if someone were to submit something and say, "We invite you to consider this, but it is, for one reason or another, confidential," then of course we would respect that, but--

So, let's get started, and we'll go to the first panel. Thank you very much. Lot has reminded me that I need to ask each of the panelists to always identify yourselves for the benefit of the people on the webcast. And it may seem in a little awkward, you know, as we go through this conversation, each time, you know, to be introducing yourself to other people around the table, but that's really not the purpose here.

So, on this we have two panels. One is-- the first panel is primarily a group of folks who think about policy issues, and we want to lead off with a discussion with those folks. And then the second panel will be a more technically-oriented panel. That is-- the idea is that the first panel will sort of think about issues that pertain to the basic framework within which we would do this study, and then the more technical folks will help us address questions about well, okay, we've got this framework, now how do you fill in the boxes. So, that's the procedure we're going to follow here.

So, I'm not going to attempt to introduce the panelists to you. I'm going to refer to them principally just by name and ask them then to introduce themselves. And then also, as I don't propose to go in any particular order, I think that we'll probably start at one end of the table and just move around. So, with you, Commissioner Wise, if you'd start us off.

Stan Wise: I would be glad to do that. Good morning, everyone. I'm Stan Wise. I'm on the Georgia Public Service Commission, and I'm in my 14th year now with the Georgia Commission.

First, let me just go ahead and say that long-term congestion in Georgia is not an issue. It's not a problem. I think most of the reports and most of the studies have shown that to be consistent, and the case and from what I've seen, probably in the Southeast as well.

One of the things that we do in Georgia, we address the long-term or congestion issue through the IRP and RFP process that Georgia Power periodically goes through in the state. We are one of the first states to initiate an RFP Program. I think, probably-- I mean an IRP.

Gosh, I guess it's going on getting close to 20 years now since the Legislature, in their wisdom-- which they don't always get right, but in this case they did-- that we've had an IRP process and it's worked very successfully. At least in this case, and that through the processes, and generation, transmission are jointly studied to determine the least-cost options and solutions to try to identify the total generation and transmission needs that would do the submitted proposals.

Let me also go ahead and say that our RFP process and IRP process has continued to evolve. It has become more transparent. A lot of people are given an opportunity to see and bid and comment on our process every time it's opened up. Once the least-cost option is selected, the transmission improvements necessary to ensure that that generation proposal can serve the consumers without congestion are identified and planned for.

One of the great benefits that we have in our state as well is integrated transmission system. All of our electric providers, our rural co-ops, our electric cities, the city of Dalton, which stands individually and owns some of the nuclear generation in our state today, all participate in this process, and have a significant contribution and involvement to make sure that the system works and works very well.

It's significant to note that Georgia Power is currently in the queue to build two new nuclear plants in Augusta on the site of Vogel. We'll start to review some of the filings that are coming in in the near future. We do not anticipate the next generation of nukes to be an issue for congestion in our state. And the great news about the long-term process is it does give us time to continue to address the needs as we go forward. Atlanta continues to be an issue because of significant growth. In the past, and still proposed in the future, and we'll continue to have some transmission needs there as well.

We've got some new combined cycle generation up and running by 2012, and I think we're going to see some additional transmission needs there already in the process. That will continue to happen. So, it's an issue in our state but it's something that I think that we continue to monitor and watch, and the companies do a very good job of it. Certainly we're aware of the Florida issues and the congestion at the line. We still think that it's a busy area, but not necessarily one that would qualify in the term congestion. So all in all, the report from this great state is good, and positive, and that we'll continue to move forward.

David Meyer: Thank you, commissioner. Now, David Till.

David Till: Thank you, David. I'm David Till, the Transmission Planning Manager for TVA. I'm in a little bit unusual position to be on the policy maker panel. I've got a lot of confidence in my peer utility brethren that they're going to cover so many of the things that you need to hear from the utilities, the sources of data, some of the projects that TVA has partnered with the other utilities, and I'm sure that they're going to mention. So, I'd like to just make a high-level perspective statement, and then speak to the benefit that I think this study can provide us all.

TVA's congestion has changed somewhat in the last three years. We have less congestion on the northeast of our system and more to the west. Some of that is due to, not steel that we've put in the ground, but to ratings that we've been able to raise because of work that we've done on the terminal ends of very important lines to allow more flow across our system.

We have implemented a regional planning process. We, within our region, work with AECI, EKPC, Big Rivers, and others. Of course, our reliability coordination footprint is even larger than that, and through the regional planning process I think that we're going to see some benefits, but that's more to the future. We've just initiated that. We're not seeing great benefits yet, although we're seeing the promise of great benefits.

Harking back to the last congestion study and the designation of NIETC. I was old enough, rude enough perhaps to say that in designating NIETC that national interest corridors really hadn't been established unless the federal government came to the table with some money. Unless there was some money there, there wasn't anything that said it was a national interest.

But I was pleased with the study, and I was pleased with the designation of the national interest corridors, and there was some backstop authority placed on those corridors. So, I think it was beneficial. Looking ahead to this study, I'm very pleased with the approach that DOE is taking toward this study. I see great benefit toward identifying this congestion, even though national interest corridors may not be designated out of this.

To take a tangent for a moment, TVA--as most utilities--is placing a great deal of emphasis on demand-side management right now. We've gone public that we have a goal of 1400 MW by 2012 that we're going to find in demand-side management. And so, we're striving to cut down on the plant that we put out in our service territory. We're striving to not bother our service area, our property owners, any more than we have to. But when we do, what do we do? And there's not anybody in this room, probably not anybody listening that doesn't have their favorite story of that. That story maybe painful, that story may be humorous.

In a past life with TVA I went out to a property owner's farmhouse to speak with her about an issue that she had with one of my line crews, and she took me to the road that ran in front of her house. And she said, "Young man," and I was then, "You need to understand. The hatred that I still bear toward the State of Tennessee for splitting my daddy's farm with that highway. Now, with that being said, you'll understand that we're nowhere near the statute of limitations on my anger that your transmission line cost his property."

We want that to happen as little as possible. However, it has to happen, and we all know that. I trust, that out of this congestion study, David, we can initiate an educational process that we are all coordinated in where the cost of congestion is put in front of the public, particularly in a time when there are economic concerns in our country that the costs to our country from an economic standpoint, from a security standpoint, are placed in front of the public, and that we educate them and perhaps can cut our costs in the things that we have to build by reducing public opposition. I hope that we can do this with the results of your study.

David Meyer: Thank you. Let me turn to Charles Terreni?

Charles Terreni: Thank you. I'm Charlie Terreni. I'm Chief Clerk of the Public Service Commission of South Carolina. And I also would like to thank David Meyer and the Department of Energy for giving us this forum to address these transmission and congestion issues. And from our standpoint in South Carolina candidly, to learn, a little more about them and to learn about the approaches that other states maybe taking toward these issues.

I say that because-- and the truth of the matter is-- that in South Carolina, at least at the commission level, congestion issues don't arise that often. We are, in one sense, blessed in the sense that we have been fortunate not to have congestion issues of great magnitude in our state. That can probably be attributed to the nature of our service territories and the nature of the way our utilities do business in producing largely their own power.

But, it also has to do with the planning process in South Carolina which relies, primarily, on the utilities. And you'll hear from them in the coming panels to resolve these transmission issues and congestion issues through regional organizations such as the Southeast Reliability Council or the Virginia-Carolinas Reliability Council.

So, largely, these matters get resolved by the utilities at that level before they would arise at the PSC through means such as our Integrated Resource Plans, which Commissioner Wise mentioned in Georgia. We have them as well. They are 15-year plans that are filed by each utility with Public Service Commission and updated on a 2-year basis.

These plans do address transmission and congestion issues and have discussions with those. We also, of course, would deal with them through siting applications either for transmission lines or for new facilities. Congestion and the need for lines is, of course, the factor in each of these matters.

What's changed since 2005? We also are-- have the potential, at least, for four nuclear reactors to go on-line in South Carolina within the next decade. South Carolina Electric and Gas Company has applied to begin construction on two reactors-- two additional reactors at its Jenkinsville facility. And Duke has received preconstruction approval, at least, from the South Carolina Commission to explore the possibility of adding two reactors to its Cherokee County site.

Now, these reactors, obviously, would produce power in excess of what is needed by South Carolina residents and perhaps even by North Carolina residents. The Duke application involves a partnership with Santee Cooper Electric Cooperative in South Carolina. It originally had been a proposed partnership with Southern Company which is no longer. And I imagine that some transmission and distribution planning issues could arise once these reactors go on-line within the next ten years.

That's not to say that there will be a problem or that's not to say that there is no need for the load, but I'm foreseeing that power would be distributed in a wider range. The issues may be more complex than that. Thank you.

David Meyer: Commissioner Sullivan.

Jim Sullivan: Thank you, David, and I would like to thank you and DOE for providing this forum. I am Jim Sullivan and I apologize for not mentioning that up front. But I do appreciate the opportunity to be here today and to relate a little bit about what we in Alabama are thinking about transmission and where we're going from here.

I do, also, want to mention that I do have the two of our staff people here today, and they'll be taking notes and they'll be available for comments later on if anybody has questions for them of a more technical basis and not policy oriented.

I would like to state for the record that Alabama will have some written comments that we would like to include at some future point for the record. And with that, those preliminaries, I would like to say that it is, in addition to our participation here today, the Alabama Commission does look forward to providing whatever further assistance will be needed as we go through this process. Our study of the 2009 study and it will also submit comments later as I mentioned, as we deem necessary.

There are three things I want to talk about today. One of them is DOE's 2006 transmission congestion study results as they pertain to Alabama and the Southeast. Secondly, trends in Alabama that have continued or have been developed since the 2006 study. And then thirdly, the manner in which congestion is addressed in Alabama.

As you all probably know, the two predominant electorate service providers in the state are Alabama Power Company and TVA. Alabama Power serves primarily the lower two-thirds of the state. TVA, on the other hand, serves the upper one-third of our state. In addition, we do have various community systems and rural areas served by electric co-ops.

The commission is charged with regulating all of our power used in the state, and in Alabama that would mean particularly and exclusively Alabama Power Company. Alabama Power, along with Georgia Power, Mississippi Power, and Gulf Power are all subsidiaries of the Southern Company, and they provide retail electric service to portions of Alabama, Georgia, and Mississippi, and the panhandle of Florida.

Now, I would like to briefly comment on the 2006 transmission congestion study and address to some degree the congestion issues related to Alabama in particular and with the Southern Company region in general. I will not speak too deeply about the Southern Company. I think that would probably be better left for maybe the panel at large and maybe the next panel that's going to be following us.

But first I'd like to emphasize that the 2006 transmission congestion study directly concluded that Alabama Power Company, as far as the Commission is concerned, does not have any major congestion problems, and in that sense we're like Georgia. Stan Wise mentioned earlier. In fact, we've found that there were no areas of concern in Alabama.

There were no areas of critical concern in Alabama. There was one conditional area of concern, but that particularly was the situation that is developing in Georgia with the possible building of the two new plants over at Vogel, and of course that is centered around whether or not adequate transmission would be available. We've already heard Commissioner Wise mention that, and in fact, we don't see any problems there, and we feel that that's very-- that that's a problem that's not going to occur.

As I mentioned earlier with regard to Southern Company's larger footprint, we feel very comfortable in Alabama that they are interfacing with the other states that are contiguous, the other companies that they interface with, and I feel certain that other speakers will have more to say about that than I would be able to add at this point.

Again, I agree with the 2006 study's conclusion that Alabama Power service territory does not have any significant congestion. This news did not come as a surprise to me. For many years now the primary indicators which signal the absence of congestion have been positive for Alabama and for the customers in Alabama.

Such indicators include, first, TND reliability ratings that are in excess of 99% in our state. Low retail prices, which consistently rank from 20 to 15% below the national average. We do have an exceptional fuel diversity in Alabama, and specifically, I will tell you that in Alabama coal is about 47% of our fuel supply. Nuclear is now 12%, natural gas 16, PPAs, that are all natural gas fired, would be about 12 or 13%, and hydro generation is now a little less than 12%.

In an effort to mitigate any significant transmission and congestion, Alabama Power continuously invests in its transmission infrastructure. My staff tells me that, for instance, Alabama Power has invested over $365 million from a period of 2005 to 2007, and it's budgeted to spend an additional 123 million plus and if you go back to 2005 and bring that up through 2008, that 's almost a half a billion dollars in transmission the Alabama system is going to be improved by.

Alabama has also experienced significant economic development over the last ten years, and it has become a preferred siting location for many new industries that have located within our state. We think that much of that success, in large part, is due to the strength of our electric infrastructure. For example, over the last ten years the following major companies are located in Alabama and most of these have cited that low electric rates and high electric reliability are major considerations for locating in Alabama.

Going back to 1995 you may recall that Mercedes Benz was one of the first large companies to come to our state. And since then Tuscaloosa Steel, Mitsubishi, Polysilicon, Ipsco Steel, Honda, Frontier Yarns, Hundai, Berg Steel, Kronospan, Louisiana Pacific, Thomasville, and the latest is Thyssen Krump Steel company which will be the largest steel prefabrication company-- or fabrication company-- that is located in the world has now announced that they are going to locate and are in fact under construction in Mobile County in Alabama.

That all adds up to a little bit more than 16,000 new jobs that have come to Alabama, and we feel like that that's a good indication that our electric system, including transmission, is in really good shape in our state. Therefore, significant congestion is not an issue in Alabama Power Company's service territory, and again that is the only company that we regulate.

And this is a major region for a lack of long-term congestion in Alabama. It remains a state in which both generation and transmission, along with distribution and demand-side management, are all jointly studied through, again, like Georgia, our Integrated Resource Planning process to provide service to consumers at a least-cost basis.

This process, reliability, and long-term economic dispatch are the primary drivers for the system improvement and system expansion plans. This integrated process reduces congestion by ensuring that Alabama Power's and Southern Company's generation can provide service to the citizens of the region on a long-term basis. The results of this Integrated Resource Planning are incorporated into CERP and into NERC studies so as to ensure reliability and also more information availability.

Outside of planning for a long-term economic dispatch for native load customers there is also a process in place to provide long-term firm transmission service to third parties. Should a third party desire to have transmission involvement made to address a congestion problem that it has identified, all that a customer has to do is to commit to taking long-term service under Southern Company's transmission tariff. If such a commitment is made, then Southern Company would move forward to make the transmission enhancements necessary for that third-party to receive long-term service. Firm service.

In conclusion, we believe that DOE's 2006 transmission congestion study does in fact validate the benefits of our Integrated Planning Process. The benefits are demonstrated by positive trends in such areas as low prices, high reliability, fuel diversity, and economic development. In looking forward, my staff is telling me that we should have high expectations that such trends will continue in Alabama. And again, David, I appreciate the opportunity to be here today.

David Meyer: Thank you, commissioner. Next we have Cindy Miller from the Florida Commission.

Cindy Miller: Thank you. I'm Cindy Miller and I'm a senior attorney at the Florida Commission. We're part of Florida also. I should note at the start that our commission is made up of five members. They're in an agenda today and that's why I'm here. And they take action through orders and rulemakings, and so I'm going to try to stay within that framework, but I'm still speaking for staff. And I have with me Steve Garl, and he's with our electric technical staff.

Florida has a system in place for addressing transmission needs. I see two components to it. One is, the Florida Public Service Commission role and the other is the Florida Reliability Coordinating Council, FRCC. And, just as some of the other speakers, Commissioner Wise in particular, said that they see more transparency in the process, that's what we see, and we see the comparability principle and treating the customers with the same approach as themselves. We see those things taking place.

The Florida Public Service Commission has a ten-year site plan process. I noticed South Carolina has a 15-year, and I notice the IRP process in Georgia. We have a ten-year site plan process, and our next workshop is in August, August 12th. Basically it addresses the plans for the plants for the future but also the transmission needed. That includes transmission studies and a full discussion on those needs. That process was instituted by our legislature.

We do a report and it goes to our Department of Environmental Protection. So, each year we hold these workshops and that's where these issues are addressed. Also, the commission has authority through some statutes known as the grid bill. And, that's the way that we can take action on the conditions on motion. So when transmission issues arise, that's the way to approach it.

Previously the Florida Commission did see a problem in the central Florida area. So, you know, we saw the need for improvements, and those are under way, and the projects are to be completed by 2012. We will hear an update on that at our August 12 workshop.

On the Georgia-Florida interface, and we also saw that in the 2006 report, we too have not seen that being a major issue. As you know, Florida is a peninsula state so we're not having the transmission come in from all sides, but what I think has happened is more of an approach with self-sufficiency and having more generation developed.

And so I know that in our last ten-year site plan report which was issued December of 2007, there was a statement in there about that interface that concluded that, based on studies performed by the FRCC and Southern, there did not appear to be any reliability constraints at the Florida Southern interface at this time concerning the current use of interface capacity.

I should mention the Florida Legislature, which finished its session in May, did pass a really major bill, House Bill 7135. If anyone wants to see that, I would be glad to get you a copy. But basically in there there were several provisions to facilitate transmission. And there’s stuff on alternate corridors and also on cost recovery, especially on the cost recovery it was facilitated for nuclear plants and IGCP plants.

We have-- the Public Service Commission has issued need determination for some new nuclear plants, so those are on the horizon and new transmission maybe entailed with those according to our technical staff. Thank you for the opportunity to be here.

David Meyer: Thank you. A couple of points here. I've been asked to clarify that if parties send us confidential materials, we have to tell you at this point that there are contingency situations-- possible situations where we might not be able to protect the confidentiality of that material. That is, if we get into certain legal processes or sometimes FOIA requests that we're not always able to protect such materials. So I just need to alert you to that, and you just take that into account. And I also want to repeat that to the maximum extent possible we want to rely on publicly available material.

So-- at least three of you have mentioned new nuclear plants and the question of transmission associated with those new nuclear plants. And I wanted to ask you for more detail on that about the state of the planning process with respect to new nuclear capacity because my understanding is that the NRC, the Nuclear Regulatory Commission, has some very stringent requirements about grid support for nuclear power plants.

And I realize that in most of the cases we're talking about here were talking about adding new units at existing nuclear sites, so-- but nonetheless I guess my expectation going in would be that the transmission capacity that serves those existing sites was probably, for economic reasons, was not sized in such a way as to accommodate major additions of new generating capacity in those general areas.

So my presumption is that adding new nuclear units, even after these existing sites would require some significant transmission upgrades. And so that's why I'm particularly interested in upgrade-- the planning-- the transmission planning process with respect to these new nuclear units. So, if you can just tell me where things stand on that.

Stan Wise: Stan Wise again from the Georgia Commission. There's no question that it is an issue. Georgia, just for jurisdiction, Georgia's issues about transmission generally is a light touch. It's reviewed, it's something that goes into our overall approval of that process, but ultimately I think the NRC will have a more stringent review and a process that would ultimately sign off on those issues.

But clearly the two new nuclear plants are proposed at an existing site, there is significant transmission in place, but yes, it will require additional work to make it ready for, you know, certainly the proposed date, 2016 or later. It gives us-- companies adequate time to take care of that business.

David Meyer: Is this-- adding additional capacity of one kind or another at the substations or does it require new line capacity or what…?

Stan Wise: I think the combination, certainly.

David Meyer: Could I ask Commissioner Sullivan and Cindy Miller to…?

Cindy Miller: I'm looking at Steve Garl, our technical staff, and he nodded his head that ours too.

David Meyer: If he wants to--

Cindy Miller: Oh, that would be good.

Steve Garl: Thank you, Cindy. In Florida's case we've got four new nuclear power plants on the horizon. The first that we're envisioning coming on board will be Greenfield plants, which initially might make one think there would be some significant transmission issues there. But the two plants will be within approximately 5 miles of the Crystal River site where we have five generating units down there, one of them nuclear. That helps out somewhat.

In addition, as Commissioner Wise said, the time frame for getting these new plants online allows the time for them to go out and work the transmission issues. Much the same is true of the two new plants at Turkey Point. And I should mention, all four of those plants are 1100 MW for a total of 4400 MW here within 10 years. The ones at Turkey Point are at an existing site which greatly helps out the transmission issues there. That pretty much answer your questions, David?

David Meyer: Well, and again, the changes that you anticipate, is it possible to say what kinds changes you have in mind, or is that still under analysis?

Steve Garl: It's under analysis right now, but preliminary discussions, just as in the case in Georgia, is the whole mix of transmission system from the lines and substations and on into distribution areas.

David Meyer: Thank you. Sure. Commissioner Sullivan?

David Till: As far as PDA is concerned-- I'm David Till with TVA-- all of our nuclear that we have installed and are planning on installing is at existing sites. I didn't mention it because we don't expect any congestion out of those units. We'll put the transmission in place to avoid any congestion.

Specifically to your question, we have not seen problems with GDC 17 offsite supply for safe shut down of those units. Our-- the things that we've seen have been thermal issues associated with getting more power out of those sites and stability issues. We have not yet put anything in place or gotten board approval for any site that required a new line.

We have been able to upgrade existing lines and change the technical aspects of protection on the system to avoid any problems. That won't be true in the future, I'm sure, but I really don't expect the problems to center around grid support for the plant. I really expect it to be issues with getting that power out into the loads. Sorry, Jim.

Jim Sullivan: This is Jim Sullivan from Alabama. And I think it's probably very appropriate that Garl went ahead and mentioned his comments before I did because Alabama and Alabama Power Company and our commission actually have no nuclear plants coming on that will come in under our authority. But we do have, basically, three states that are, you know, Georgia and then we have a TVA plant and then we have Florida that are all either contiguous or located in the northern part of our state although unregulated.

And, I think that's just another way to illustrate that our Integrated Resource Plan reconfirms and reassures that whatever is going on around us is going to be well taken care of and is going to be studied well in advance of the time that we really have to worry about it.

And Alabama, what we're looking at right now, and we don't see any problems with it-- as a matter of fact we feel very comfortable that we have an excess of capacity-- but what we're looking at right now is really the Florida Panhandle, the Alabama coast, the Mississippi Gulf Coast where we do have casinos coming in in Mississippi, we have a lot of development, as I mentioned, in the Mobile area, and the panhandle Florida has always been a very big tourist attraction area.

And basically, what we're trying to do is just make sure that the adequacy that we have there and the redundancy that we have down in that area continues to be and continues to serve that whole three state area as well in the future as it has in the past. And I guess what we're really looking at is just to make sure the redundancy is there in case we do have another Katrina-type hurricane come in to that part of the state.

But we have looked through our RFP process and what's going on with nuclear plants in and around Alabama, and I guess, just from our perspective, we can reconfirm what the other three participants have basically said, that we feel very comfortable those nuclear plants are going to be well fed and that there will be adequate transmission coming out of there.

Stan Wise: David, I've got a question for Mr. Sullivan if I could. Jim, that was a pretty impressive list of new industry that Alabama has attracted. Clearly. I'm vaguely aware that Georgia has not attracted some of those over the last decade, but how do you in your process anticipate that huge industrial growth that you've seen when your IRP process might look at 10, 12, 15 year periods ahead. And I know you said you've got some excess capacity, but that steel plant in Mobile has to take huge new needs that-- how do you plan for that industry?

Jim Sullivan: Well actually, Stan, that steel plant is going to take a lot of energy including gas. And, you know, that's just something that we've looked at over the years. Again, the RFP process, the Requests For Proposals, are all mixed in to that process that we use.

And in Alabama, we're constantly gathering information from all the contiguous states. We're gathering information before these plants come in we know what their load is going to be, we know what their expectations are going to be, and I guess really instead of focusing on something that we feel very comfortable is going to be taken care of and that we do have a plan for, and we incorporate that also into the panhandle of Florida as I mentioned as well as to what's going to happen in Mississippi with the casinos along the Gulf Coast.

You know, one of the things we're a lot more concerned about is how in the world we let that Kia plant end up over in Georgia instead of getting it over in Opelika Alabama. And we don't know what you did to get that, but we're looking into that. We wanted it too.

Stan Wise: You can't have it all, commissioner.

David Meyer: Well, let me turn to another topic. Fuel prices have just amazed and astounded everyone. The volatility that we've seen and some of the price changes that we've seen, and this isn't a problem that is going to go away. I think this will be with us for a while. But I wanted to ask you what changes has this meant for you it in terms of the way the transmission system is being used. Are you drawing on other plants and transmission lines more than you used to? And I'm just trying to get a sense of how-- what's-- how have things evolved in this sense since 2006? Is this a question for the second panel?

Stan Wise: That's past me. I didn't bring any technical staff, so-- it would have been easy, I guess, but they're not here.

David Meyer: I understand. Maybe some of the others, then.

Jim Sullivan: David, this is Jim Sullivan again. I'll just make a passing comment and say that my staff tells me that we do have extremely adequate reserve requirements for any anticipation of any additional load in Alabama, and in the of the event that any IPP wants long-term firm transmission, they can get that through a contractual process with Alabama Power Company.

And to my knowledge, and it's my understanding that there's never been a contingency there. Every time an IPP has asked for long-term availability that they've been able to get that so we don't see what is-- we don't see an existing problem. We are very, very, acutely aware that nationally one of the problems that seems to be evolving is the fact that renewables may be located, or generation maybe located in one part of the country but there's going to be a need for transmission to get those renewables to other places.

And Alabama-- we do not have a lot of wind. We think over the long term that solar may be a renewable that we'll be dealing with, but it's certainly not part of the process at this point in time. But we are very aware that in the future that might become something that we need to look at more thoroughly, but our reserve margins right now in generation and transmission are certainly adequate to take care of anything that we foresee in the short-term or the intermediate future.

David Meyer: Commissioner Sullivan has anticipated my next question which was, there is this general increased interest in renewables. And in some areas this does occasion greater importance or the prospects of greater importance. Or I could see imports rising perhaps for other reasons as well. Perhaps due to price changes or the addition of additional nuclear capacity that might lead to exports. Exports on one side and imports on another.

So let me ask the panel about those kinds of questions. That is, focusing upon increased imports or exports for whatever reason. Have you seen changes of that sort since 2005 or 2006 that are notable?

Stan Wise: Stan Wise again. We're not seeing a great deal. It generally-- you know, some of the new opportunity for generation we're reluctant to embrace until prices can be more compatible with the current generation mix.

And clearly, natural gas prices have driven a lot of fuel cost pass-throughs in our state but weather solar it is an option in the South still remains to be seen regardless of the T. Boone Pickens ad campaign. We don't-- you know, I don't know if he's selling natural gas or solar, but I'd have to say that clearly solar, with the technology, the price, and the fact that we're going, even on our hottest summer days we're going to still have significant cloud cover, we still think renewables have a way to go in our state.

There's even talk about whether to biomass from wood chips. And clearly if you get out around the state of Georgia you see an awful lot of pine trees. But the long-term capacity even for that is a drop in the bucket compared to the needs that we're going have in the next 20 to 25 years, and that fuel diversity is as important as it is, we think renewables have a long way to go. Even those that say they have the technology today. So it's not a concern of ours today, it's not something that has continued to drive us on some of our decision making because of all the other external variables that we take into effect when we look at the IRP process.

Cindy Miller: Cindy Miller with the Florida Public Service Commission. I probably should mention, since we're talking about renewables, that this new legislation that passed this year in Florida, House Bill 7135, also requires the Florida Commission to establish a renewable portfolio standard. And that will go back to the Legislature for ratification. We have to complete it by February 1. So we have started holding workshops on the renewables, but-- and we had held some previously last year.

Thus far transmission, at least to my knowledge, has not been a major issue brought up in those workshops. And also, technical staff had asked me to mention that, you know, in addition to transmission, you know, there are these other matters with the pipelines and with transportation for coal that I should mention as also important since we still have the coal plants in our fuel diversity as well.

Charles Terreni: This is Charlie Terreni in South Carolina. With regards to renewables, I would say what Cindy said, that transmission hasn't been an issue in the renewables area. Because we are not yet at the point of having these programs underway, but they're certainly on the minds of the Commission and the Legislature and the companies.

The South Carolina General Assembly passed several statutory measures providing incentives for alternative fuels in the past session. And also I think there's a great deal of concern in the industry consumer groups as well about the eventual cost of potential federal legislation on a coal-dependent state like South Carolina.

Even if nuclear plants that haven't been approved yet that are being applied for should emphasize, were to go online they won't go on line for another ten years, and if you had federal initiatives entering the breach, depending on how they're configured, the cost implications for South Carolina consumers could be tremendous. So, renewables are certainly something that are being looked at in South Carolina, but as far as affecting transmissions we are just not at that point yet.

David Meyer: Let me go back to the subject of projects that are under construction. Those could be generation projects or transmission projects, or things that are in the regulatory process that are in mid-stream that we should know about. And I just want to make sure that we get those projects listed out by-- sort of by name if possible. So it just makes it easier for us to track.

Stan Wise: David, this is Stan Wise again. I mentioned something in my preliminary comments about 2500 MW of new combined cycle generation. It is to replace some-- an existing coal plant in the metropolitan Atlanta area probably not five miles west of here. It's Plant McDonough.

It's right on the river, and for a variety of reasons including, you know, an older high-cost admitting plant, it was easier to go ahead and mothball and the commission, I'm losing track of time-- it was either last year or early this year we approved that and so that's where some of that new transmission in Atlanta proper will come from or be generated because of this new combined cycle plant at McDonough.

David Meyer: So-- and adding that capacity--

Stan Wise: And I do know how to pronounce it by the way. We-- every state has different things-- it's not "McDonna" it's "McDunna." Am I right, Andy? Thank you.

David Meyer: But it-- did I understand that that will require some transmission changes?

Stan Wise: Yes, sir. Yes, sir. In fact, some of the local government jurisdictions are being informed of that as we speak. I'm not sure the public's quite aware of and it's going to go through, as David mentioned earlier, some areas that are probably a little sensitive. Some of Atlanta's finer suburban areas and it's going to-- there's going to be some guys having to have to cross some bridges and explain to some folks how transmission society works.

Once again, we don't have any jurisdiction over that society. So we get the phone calls and the complaints.

David Meyer: And who does handle the society?

Stan Wise: It is done by state statute. Fiat. Eminent domain.

David Wise: So, that is, at a certain point the Legislature has to--

Stan Wise: No, sir. They don't pass on it either. By statute, the companies have the right to site transmission in our state. Now, through the last couple of years, there has been a cleaned-up process where people know how many public hearings there are going to be, when in fact the lines are shown, were they're going to go, what some of the alternative sites were, and that came I think about three years ago.

Some of the new lines were going through some of northeast Georgia's most pristine mountain resort areas and they were going hilltop to hilltop. As again, David probably knows, from Tennessee, that's the easiest way to go, but it wasn't the most politically expedient. So, the companies kind of run roughshod in the process. There wasn't anybody that knew what came when or how it was presented, and I think the Legislature cleaned that up a couple of years ago. But still, the powers of eminent domain remain with the companies and with the transmission corporation.

David Meyer: Others want to speak to that particular project, transmission or generation that are under construction or in the regulatory process that we need to pay particular attention to.

Jim Sullivan: This is Jim Sullivan with Alabama again. I'll just say that, again, we have very adequate reserves of transmission and generation in Alabama. Proper and I will say up front that Alabama and-- that we do interface with TVA, we do interface on the west with companies in Mississippi, Entergy, and TVA as well, again. We get into of course, Southern Company Affiliates, Alabama Power, Mississippi Power, at the southern end of the state. And then we have that area down in the Panhandle that I mentioned before as well, and then on the eastern side, of course you have Georgia Power, Alabama Power, and then you have TVA again in the northern third of the state.

So, we do have a lot of interfaces in Alabama, and then of course down into the Panhandle and across the southern part of Alabama into Florida. And I will say that over the years that there could not have been a better working arrangement among all of these companies in our region and they work very well together.

And again, through an IRP process, we understand what not only is happening but what is going to happen, and in Alabama we take Alabama Power Company looks at what we think is necessary to make sure that all those interconnections are serving all the states and the region well. There has been some funding committed to those interconnections, and of course there will continue to be funding that makes sure that that Panhandle area of Florida and Alabama and over into Mississippi is also given adequate supply and adequate transmission power.

Basically, as far as we can tell at the Commission, and what the staff tells me is that there is nothing critical out there. Nothing has been identified as having to be done on an expedited basis. Most of what we're doing in Alabama, if not 100% of it, is just in anticipation and making sure that we're ahead of the curve in taking care of the system.

David Meyer: Let me go back to the discussions here as far as-- public commissioners in particular about fairly rapid growth in, at least in some areas. So are there particular planning studies associated with that rather rapid major industrial growth that we should pay attention to? Any published materials that we could dig into and learn from?

Jim Sullivan: Well, this is Jim Sullivan again, and of course again, for the IRP and RFP processes, there's going to be information that's available from the companies. There's going to be information that's available from the companies through our staff at the commission.

A lot of the information that is obtained also would end up being available either through CERP or NERC and all of that information would be available upon request. And we feel like, again, Stan mentioned up front, one of the first things that he mentioned was that we feel like that as we're going through this process of making sure that we do have adequate reserve margins in transmission as well as generation. That we are becoming a lot more transparent with what we're doing because, actually, we're interfacing more with the contiguous companies and states with that information because it's coming from both directions.

It's going to be available not only from Alabama Power Company but from the other companies as well. And, we think there's a transparency there and I think that any time that you needed information if you would ask for it on a specific basis that it would be forthcoming either through the Commission or directly from the company.

Stan Wise: David, it's Stan Wise again. Just one caveat because I believe my answer would be identical to Jim's. Clearly some of the filings on our IRP are trade secret. It wouldn't be our opportunity to divulge those without approval from the company, but perhaps if requested directly from them available under trade secret protection. And again, I don't know, with your caveat that you gave in your opening comments on advice of counsel I guess--

David Meyer: It's a-- there is a sticky point there. Are there studies underway that you know of that we should anticipate and things that you want to bring to our attention? And all of these requests, I want to say, you don't have to deliver on the spot, but you may want to send us information later or ask your staff to send us something in the next few days. But I just want to make sure that we do get the follow-up.

Stan Wise: Stan Wise again, David. I think one of the things that I mentioned in my opening comments talking about that next generation of nuclear plants, we're expecting some filings this week. And I think as we go through the beginning of the certification process in the state there will be some issues that I think that you should look at and be aware of. And as we go through the process, and I see the filings, and we have our hearings perhaps I'll be able to see something that I can forward and send on and make a part of the commission's comments as we go through our process on certification.

David Meyer: We-- if there are certain dockets that we should be following, you know, or something.

Stan Wise: I don't have a docket number on it. But clearly there's one established. And what can be made available is generally available on our web site subject to trade secret protection and they're all filed electronically today and it makes it very easy to review some of that as it comes through.

Jim Sullivan: David I just-- let me just chip in here and say that I asked that question specifically to our staff. And they said the only thing that right now is really being studied is the possibility of what can occur in Georgia. But I think that really illustrates how the IRP process works on a regional basis.

The fact that we in Alabama would already be cognizant of what's going on with the nuclear plants that are scheduled to come on line I suppose sometime in the next two decades. And-- but it's a good indication that we are exchanging information. That information is readily available, but as far as anything peculiar or particular in Alabama, at this point in time—there is none.

David Meyer: Well, how does that IRP process work at the-- between states? That is, is there a kind of an established process for sharing, or are you all on more or less at the same schedule? Or do you just distribute materials to each other as they become available, or how does this-- how do you stay in step with each other?

Stan Wise: I'd say none of the above. What-- you know, ours is once again, established by statute, done every three years, and done specifically. Now, is there and can there be a hearing? Yes. But is there a requirement or do we do that? No.

It's just-- I guess, in the process it is such a big docket though that people that are filing and intervene in these cases are aware of what happens in South Carolina and Alabama and Mississippi and Florida. So, we do see that become a part of the process and are aware of some of the constraints that may be in place but it's something that we're not required to do nor do we do.

David Meyer: Do others want to speak to that?

Charles Terreni: Charlie Terreni in South Carolina. As Commissioner Wise said, at the commission level there is-- all of these cases are public docket. They're contested dockets in the cases of the nuclear plants. Their office of regulatory staff in South Carolina, which is an independent office and represents public interest for the commission would be coordinating-- if they wanted to or if they needed to-- with the North Carolina staff.

Also, in cases of utilities in South Carolina that are doing business in North Carolina as well, and Progress and Duke, we're going to have necessarily corresponding pieces of the IRP. It wouldn't make any sense otherwise.

David Meyer: This may be a question that you, again, would say ought to be deferred to the second panel, but I want to ask you whether you have a particular definition of congestion that you use, or particular ways that you and your staff-- particular metrics that you regard as important. We-- I'm just trying to get a sense of what the term "congestion" means on your side of the desk.

Stan Wise: My answer is "yes" on the first.

David Meyer: Any others at the table want to speak to that.

Jim Sullivan: Well, I'll use this DOE low-bid mic here. If I can keep it together.

David Till: Commissioner, you're cracking on a line of products, probably. I mean, the Western doesn't even have windows in the hotels, so…

Jim Sullivan: Well, I think in Alabama that-- I don't think there is congestion-- there is no per say way that we can measure congestion. Again, I would revert back to the IRP and the RFP processes as ways that we do measure congestion, and they have proven to be very affective. And I would suggest that that's basically the way-- the methodology that we go about measuring congestion in our state.

Stan Wise: You know, that goes back, David, again to the integrated transmission system that we have, and so that's going to be something that's generally done by that group in our state when they do the regional cooperation. And I believe a lot of people rely heavily on the 2006 congestion steady. I believe that's what our staff looks at, I believe that the IPS and ITC that that's a major part of what they're doing. But-- to the levels that I get into it--

David Meyer: Let me turn to David Till. You may be a little closer to this than some of your colleagues on the panel here.

David Till: This is David Till with TVA. David, honestly I'm less concerned with congestion as I am with having enough transmission that we get economic dispatch of our designated native-- network resources to our native loads. So, to the extent that we can't do that, I tend to see that intuitively as congestion without a definition to back that up. Beyond that, I look at the TLRs that are called that are either called on our system or affect our system. And look to those and say, those are indicative of congestion. That's costing.

David Meyer: Yes. But a lot of times congestion may be there and people are not calling TLRs, they're resorting to other ways of dealing with the problem, and so the congestion's there but the TLR never arises to indicate it. So--

David Till: And if we don't see internally, an economic dispatch that's costing money there, then that's essentially not a concern. We're building our system to get the best dispatch of the resources for the load internally and then we're accommodating the market to the degree that we can or to the degree that the market is willing to invest.

David Meyer: Well, conceptually I think, from our side, we would say that if, because of transmission limitations you are not able to get the pattern of, you know, dispatch that would be economic, then yes, that is a congestion problem. Now, so I think we're on the same wavelength here.

David Till: So, beyond that, our regional planning offers opportunities to clear up congestion that is an economic concern to the market. Outside of our designated network resources region our native load.

David Meyer: Let me turn to others here to-- Do you want to comment on-- alright. We're getting close to the end of this panel, so I want to invite, you know, sort of in a sense of a two-minute warning, three-minute warning, if there are themes, topics, subjects that you haven't yet covered that you came in intending to speak to, now is probably your best shot. So, anyone have things they want to…

Jim Sullivan: I think, this is Jim Sullivan again, and I think-- just trying to put into perspective where we are with this issue and where we're going-- I think DOE, I think Congress has been very prudent and taking a look at where we are with transmission and congestion in looking at this every three years and coming up with answers and being forward-thinking and forward-looking.

But to put this in perspective, I've been a commissioner in Alabama for 25 years. And I think because our transmission system has been in such good shape, we've been so far ahead of the curve, this has just never come up as one of the major issues that reaches, frankly, the commissioner level. And I think that's a good indication that our region of the country is doing a good job of being proactive.

We're a lot more concerned about what Alabama Power Company is going to be paying for fuel, how that's going to factor into rates for customers from industrial all the way through residential customers. Again, I think staying ahead of the curve or what we're doing with these three-year meetings and the oversight that you're providing is critical. I think it's going to keep our region in very good shape, but when you put everything in perspective, this has just not been-- transmission has not been a very big blip on our radar screen. And I think that's good.

David Meyer: It-- I wonder if some of you have ideas about why is that so? I mean, why is your process working, or it has in the past worked and now you're reaping the benefits, but is there some particular reason that comes to mind as to why that-- as compared to other areas?

Stan Wise: Mr. Sullivan and I might say it is because we're elected in the states of Alabama and Georgia and that we're more sensitive to doing the right thing.

David Meyer: Okay.

Stan Wise: And neither one of us are running for election.

David Till: David, this is David Till, TVA.

David Meyer: Sure.

David Till: The commissioners have mentioned the integrated planning that goes on. I think that integrated planning has produced a situation where the resources in the Southeast can be dispatched to the loads. Without congestion in most cases. And, then further-- I can't speak for the other utilities, but I suspect this is true of them also-- the Tennessee Valley Authority has been quite aggressive in establishing ratings that allow post-dispatch of--

post-contingency re-dispatch of resources rather than pre-contingency dispatch of resources. So, we don't de-rate those resources unless we absolutely have to.

We've issued short-term ratings that we're confident on a technical basis of those ratings that we won't hurt the transmission lines or the transmission equipment by allowing time for a plan to de-rate after a contingency. Those contingencies rarely occur. And so, we keep the power flowing without the congestion.

David Meyer: The planning processes that you-- the IRP processes, do they allow you to build with, say, what I would call head room on the transmission system? So that you can-- there are places in the country where transmission seems to get added only kind of at the last minute. And as opposed to having some head room built into the system that you can grow into and people are not-- so I'm just trying to get a sense of, in your operations, your planning process--

David Till: I'm not going to say that we don't have some just-in-time transmission and service dates. But, in most cases the lumpy nature of transmission expansion gives us the head room that we need. And we don't take risks that aren't-- that don't have a technical basis for being very low-risk.

Stan Wise: David, I know I had my tongue in cheek my self-congratulations a minute ago, but really when I think about it it goes back to a couple of things that I said earlier, and I'll say it again. But number one was that the companies, by and large, in the South, do have the opportunities to do this without government interference.

And so that they can build out these systems without a lot of interference. And to their credit, and in our state, that integrated transmission system has worked. And because each of the providing utilities, whether it's the rural co-ops or the cities or Georgia Power all look at one another and say "Well, we have an obligation to spend this money and to do these things."

And I think it goes back at least for the last decade that we haven't put in that extra level of bureaucracy and governmental intervention and that when we were in that period of declining rates back in the good old days of the '90s, our companies, with their commission's approvals were putting in additional environmental controls, planning for the future there.

If we're going to be a 50% coal burning region, then we were taking care of our business there-- but at the same time we were aware of the cost of transmission lines. And we weren't going to go ahead and wait for the formation of some new agency or transmission organization and that-- we take a little pride in that.

And so sometimes, that less government mantra does work. Some of our more aggressive non-regulated utilities in the state will tell you that they're effective because they don't have to deal with my agency, the Public Service Commission. And so it is a number of things that I think have allowed us to be able to do that. Notwithstanding significant growth, past and future, in our states. Knowing that you've got to plan for the transmission needs that are coming if we're going to attract-- continue to attract not just industry, but people are moving in to fill those jobs.

David Meyer: Well, we've come to the end of our allotted time for this panel. I want to thank the group for some insightful discussion and things for us to think about as we go forward. Thank you very much. We will resume at exactly 10:45 and have the second panel.

[Break]

David Meyer: We will resume now with our second panel for this congestion workshop. As I mentioned earlier, the second panel is a somewhat more technical oriented panel. These are people primarily from the utility industry, the companies, the entities themselves. Transmission experts.

And they are in the fortunate position of having heard the first panel's discussion. So, if some of the questions that were discussed there pique your interest, and you have additional comments you want to add, I welcome that. And please do so.

So, with that, we will-- again, I will not introduce these people other than perhaps to call on them by name. I will rely on them to provide a fuller introduction for you, and I'll ask each of them to identify themselves by name as we get into the dialogue. So, with you sir…

George Bartlett: Thank you, David. Good morning. My name is George Bartlett. I am Director of Transmission Operations for Entergy Services. Entergy owns and operates about 30,000 MW of power plants. And we deliver electricity to about 2.7 million utility customers in Louisiana, Mississippi, Arkansas, and Texas.

I appreciate the opportunity to be on the panel to provide Entergy's input to the DOE with regards to the proposed 2009 transmission congestion study. What I'd like to talk about in my opening statement are sources of information about transmission congestion that are available, and in my view, should be used by-- would be useful to the DOE as it undertakes the congestion study.

And I'd like to talk briefly about the organizational changes that have occurred on the Entergy system since the DOE's last study was put out in 2006 with turnover of oversight responsibility for planning to the ICT. And I'd also like to discuss efforts that have been undertaken since our last study to address and alleviate points of congestion. I might save those though until the Q and A session.

First, I'd like to compliment the DOE for their 2006 study that they've put out. It's my opinion that the congestion identified for the Entergy region in the study was accurately depicted. They had six bullet points showing six sources of congestion and identifying each of those specifically and then on a map it had some other congestion points which were identified by arrows. I think that was an excellent way to portray it and again I think it was very accurately done. It matched our impression of congestion that we see on the Entergy system on an ongoing basis.

Going forward to this study there are a number of sources that are publicly available to that the DOE could derive benefit from. Entergy participates on regional and interregional transmission reliability study groups and the results of those studies can be a basis for the DOE in its evaluation of transmission congestion.

One would be Southwest Power Pole's EHV transmission overlay study. The study is conducted by SPP to evaluate transmission system expansion of the EHV system 500 kV and above to accommodate over 20,000 MW of wind generation from the Great Plains and Texas Panhandle. That's really a forward-looking study, but it provides some insight into the operation of the transmission system.

Another source would be the ICTs strategic transmission expansion plan study for the Entergy system. The purpose of that study was to promote EHV expansion on the Entergy system by identifying problem areas and developing long-term strategic solutions. The study's objectives included improving load server capability, interregional transfer capability, improving service-to-load pockets and load centers, and relieving constrained flow gates. So that has a lot of good information in that.

The Southeast interregional participation process, Southeastern transmission providers is a full-power study looking at expansion planning between the transmission providers in the Southeast. Again that's forward- looking but an excellent study.

Then there is a joint coordinated system plan between MISO, PJM, SPP and TVA. It looks at both the powered transmission expansion planning between the main barriers. CERP also has long-term study group and near-term study groups which develop reports and have worthwhile documents that evaluate system reliability and the simultaneous feasibility of proposed transmission expansion plans which would be beneficial.

And finally, the system impact studies performed by the ICT, in combination with Entergy, performed in accordance with FERC guidelines, the point to point network service. And they are posted on Entergy's OASIS. That is it just some studies that we feel would be useful.

There have been a number of organizational changes at Entergy since the last DOE study was put out, specifically introduction of the ICT, the Independent Coordinator of Transmissions. As of November 2006, the Southwest Power Pool was established as the ICT for the Entergy system. Entergy's role as reliability coordinator was transferred to the ICT at that time, and the ICT also assumed responsibility of administering Entergy's Open Access Transmission Tariff.

The ICT also oversees Entergy's transmission planning process, which makes it a very transparent process, which should help make your job a lot easier, I believe. Coincidentally, today in New Orleans the ICT is holding the annual planning summit for the Entergy system. They provide to our stakeholders that attend the summit plans for Entergy's construction moving forward. Construction projects or transmission expansion projects that the ICT believes should take place going forward and then constraint barriers on the system, and-- that are provided to the stakeholders so they can participate in developing solutions to some of the constraints.

Transmission planning within the Entergy system focuses on grid reliability, it insurers reliable load-serving capability and deliverability of firm network resources including other firm transmission usage on the system. It adheres to NERC's reliability standards and CERP supplements and we closely coordinate with neighboring transmission providers.

For example, through effective transmission system studies TVA Southern Entergy sees coordination efforts and through data exchange. And again we contain independent oversight regarding granting of transmission service and provides for independent reliability coordination.

Finally, Entergy has a transmission pricing policy that provides economic discipline to eliminate transmission congestion when it's economic to do so. It does not serve the public interest to devote resources simply to eliminate congestion, and I think that's something that the last panel talked about briefly. Regional transmission planning requires an assessment of whether the costs of eliminating a point of congestion are outweighed by the resulting benefits. That is, savings to customers or increased revenues to IPPs.

And Entergy does not view congestion as a reliability issue. We view it as an economic issue. Thank you.

David Meyer: Thank you. You gave us a lot of useful reference documents there. I appreciate that very much. Nathan Brown.

Nathan Brown: Good morning. I'm Nathan Brown. I am the Chief Operating Officer for South Mississippi Electric Power. South Mississippi Electric is a generation and transmission cooperative that provides the all-requirement service to its 11-member distribution co-ops located throughout the state of Mississippi.

I appreciate the opportunity to participate in this panel, and I look forward to any assistance I can provide in development of the 2009 study. SMEPA's member delivery points are served in three separate balancing authority or control areas, these being the SMEPA, Entergy, and Southern Control Areas. SMEPA about owns 1600 miles of transmission line, almost 1700. The vast majority of that is part of its own control area. We operate a control area with 230, 161, and 69 transmission lines.

One-third of our load-- about 2100 MW total-- but it's essentially broke up into thirds in these three different control areas. But approximately one-third of our load is served by our requirements contracts with-- through Mississippi Power Company, a subsidiary of Southern Company, and SMEPA has generation responsibilities for the other two-thirds. So obviously we're a transmission owner and a transmission-dependent utility from that respect.

From a transmission standpoint, because we serve generation in two separate control areas, we are obviously very interested in congestion and being able to economically dispatch our resources. As a result, we've had some of our own transmission interconnections that have been listed as limitations. We have recently performed upgrades to three of those. We've got transformers on the way for an upgrade to a fourth.

And I will point out David Till was up here before. He mentioned some of the interconnections that we've been working on. Back in June 2007 between joint efforts between SMEPA and TVA. We established a new 161 interconnection with TVA. So, we are very heavily involved in the planning process between us and our neighboring utilities.

We also participate in numerous regional and joint planning processes throughout the Southeast. These being obviously the CERP, because we're a member of CERP, but we also participate in the Entergy ICT process. We're also a participant in the Southeastern regional transmission planning process along with other utilities in the southern sub-region of CERP. And we believe that these processes, along with strong transmission planning criteria, are required to ensure efficient operations of transmission systems.

Now, as for specific studies and other things, a lot of folks have mentioned studies, but I want to point out other things that I think need to be looked at in addition to specific studies. I think there needs to be a look at what the transmission planning process is and also what planning criteria are established.

Everybody from a bus standpoint follows the NERC standards. If you don't, there's compliance penalties associated with it. From a load-serving standpoint, utilities in the Southeast differ a good bit in some situations. I will give you an example.

SMEPA evaluates our transmission system from a bus to bus standpoint. In other words, if there is a segment of line, even though breakers are located in those four delivery points between these brokers, we construct the system to meet a minimum voltage criteria at that remote bus. Some utilities use breaker to breaker analysis. In other words, if there's an operation between breakers, that load is not restored, and in my opinion, that results in an inherently weaker transmission system in some areas.

I think there should be a review of the TLR process. David Till mentioned this earlier. TLRs, in my opinion, are a primary indicator of congestion in the Southeast. There should be a process by which TLRs are administered on a consistent basis between reliability coordinators.

One other issue that I think should be looked at is ensuring that planning processes are followed by budgeting processes. We operate and build transmission facilities. We're well aware of the right of way limitations and difficulties associated with getting transmission routes and new facilities in service. However, you know, from a budgeting standpoint, that's an issue of budget stops transmission facilities over a long period of time. So we feel like those two should be tied together.

From a TLR standpoint, we feel like that there should be a review of the existing TLR logs. And there's been a number of them called in the Southeast. We also believe that if there is a TLR level five, then that should prompt some sort of an investigation, and there should be a mitigation plan that is established and reviewed. And, if that mitigation plan is not followed, then it should be subject to penalties by NERC.

We believe that DOE should continue to review the true availability of transmission paths for transmission customers. There are some situations where on OASIS things appear to be available. You can go out on a monthly or daily basis and confirm it and later find out that it's unavailable and it gets cut in a TLR process. So, in such instances we believe there should be a review of that process.

And, the DOE should also include a review of existing transmission paths to the sensitivity of various generation dispatches. This was done in the 2006 study, I think. I think they did a good job in that respect. So, that process should continue. But, again, South Pacific's goal, we are a nonprofit. We're here to serve our members in the safest and most reliable and most economic manner we can. And we believe that with proper planning and operation and continued investment in the overall transmission system we can achieve that goal.

David Meyer: Thank you. Next we will hear from Ed Ernst.

Ed Ernst: Thank you. My name is Ed Ernst. I'm director of transmission planning for Duke Energy Carolinas and like the other panelists, we appreciate the opportunity to be on the panel today.

Duke Energy owns and operates electric utilities in five states in the Midwest and the Carolinas, and we serve about 4 million regulated retail customers. In the Carolinas, which is where I spend my time, we serve 2.3 million customers at retail, and our summer peak loads are around 20,000 MW. So my comments today are going to be from the perspective of Duke Energy Carolinas.

And I'm going to talk about five things. One is the definition of "congestion," what I think it means. Two is sources of data that you may want to look at as it relates to metrics on congestion. Third, I'm going to talk some about how we've seen the transmission system in our part of the world be utilized differently in the last three years. Fourthly, I'll talk some about upgrades to the transmission system either that have been completed recently or will be completed soon that could impact how transmission is used.

And finally, I'll talk some about the planning studies. Some of that will be a repeat of what you've already heard.

I would say in terms of congestion, when I found out that I was going to be on this panel, I went out and reread the '06 congestion study. I looked at some of the comments from the other workshops. I reviewed FERC order 890 and 890a, and then I did a Google search. And all those kind of pointed to the same thing that, you know, in a general way you've got generation trying to get to load and it can't get there because of some sort of limit on the system, and typically an action is taken-- in many cases re-dispatch of generation to allow the load to be served. And that seems to be kind of the general fault of congestion.

I'd say, as a system planner I think about congestion a little bit differently than my system operating folks do. My operators, they have to operate what we give them. So they're taking operating actions on a day-to-day basis to deal with the transmission line loadings, or if you want to call it congestion, and that can be in the form of a re-dispatch, it can be in the form of calling a TLR, it could be in the form of doing switching on the transmission systems.

So, my system operators have three or four things in their tool kit that they can do to manage a loading on a day-to-day real time basis. As a planner, and I think this got talked about some in the first panel, I tend to think about congestion more in the terms of someone has made a request, or has identified a need to move power on a long-term basis-- that can be my own company for its native loan obligations, it could be an IPP, it can be someone who wants point-to-point-- and so I'm looking to see, can the transmission system reliably accommodate that, or are there upgrades that need to be made in terms of new transmission lines, increasing the capacity of transmission lines.

So, you know, I think about condition that little bit differently than my operating folks do. In terms of available data around congestion, since '05, Duke Energy Carolinas has retained an independent entity to oversee the administration of our transmission carrier, and we've also retained an independent monitor to monitor the operation of our transmission system.

Potomac Economics Limited serves as our independent market monitor. And one of the things that they do is they produce a quarterly market monitoring report, copies of which they provide to FERC and to our state commissions in both North and South Carolina. Well, getting ready for this workshop I got one of those reports and looked at it and lo and behold there's a section in there called transmission congestion and transmission access. So I suggest that might be a report that you may want to look at.

I did do more than just look at the table of contents, I actually read through it, and I found things such as curtailments of transmission service, TLR events, approval rates, rates on transmission service requests was some of the types of data that they reported in the most recent quarterly report that they have produced. So that may be a data source that you may want to take a look at.

In addition, on our Duke Carolinas' OASIS page, there is posted each month, a report called transmission service request, and it has a compilation of all the requests that came in for that month, how many were submitted, how many were approved, how many were denied, reasons for denial. So you can kind of get a sense of the traffic of transmission service requests in our-- 99% being approved or 99.5 or whatever.

I think George mentioned earlier, obviously, looking at the various system impact studies, other things that the transmission service providers can also give you a line of sight into if someone has made a request for firm service where there could be potentially needs to upgrade the system to accommodate that.

Since '05, in terms of how we've seen changes in usage on the transmission system, in the Duke Carolina's system, first I'd describe our system as being in the central and western parts of North and South Carolina. We do have one interconnection with TVA, but we're not strongly interconnected with TVA. So the bulk of our interconnections are to the south with Southern Company, or to the north with the companies there with PJM.

So typically, the flows we see on our system and through our system are a function of, you know, how generation is being dispatched in those two areas. If it's hot down in Alabama and Georgia and it's mild in PJM, we're going to see power go south and vice versa. And that has not changed since '05. To the extent we experience any kind of loading issues we have to manage on a day-to-day basis, typically we see those more on the PJM-VACAR interface to the north than we do with Southern to the south.

I would point out that since '05 we've seen expansions of both the PJM and MISO RTOs and markets that have had some impact on how those market dispatches work. And, from time to time we will see that once again show up on that PJM-VACAR interface that we have to manage in real-time.

In terms of projects that are not yet completed that could impact utilization of transmission, when I prepared for this, I thought about it from the context of transmission projects, but I would just say thinking about the Q and A in the first panel that Duke Energy, for its retail load in the Carolinas, has announced its plans to site and build nuclear plants, add additional combustion turbines and combined cycle units, and all those things we do we ensure through the planning process, which ultimately ends up in the file of IRP that we have adequate transmission on the ground to reliably get that generation out so that it can be economically dispatched when it's needed.

I would say that in terms of upgrades that are going to impact our interfaces with our neighbors that could potentially change how that transmission is utilized, we're in the process with TVA of upgrading the single interconnection between the Duke and TVA systems. That project is on schedule and should go into service next summer. That will create more contract path and transfer capability between our two systems. So that obviously has the potential to change how that interface is utilized going forward.

In addition, with Progress Energy which sits primarily to our east, some improvements on the Progress system and a new 230 kV tie between Duke and Progress have been identified. And that new tie line and the other improvements are to go in service by summer of 2011. Once again, that will create additional transfer capability between the Duke and Progress systems, so we would expect to see additional power move on the interface as those upgrades come online.

Studies. George went through a lot of these. I would just reiterate one or two of them. Obviously, all of the reliability assessment studies that are done under the CERP umbrella, both near-term and long-term, in addition the CERP region coordinates studies with other regions under another acronym called ERAG. The Eastern Interconnection Reliability Assessment Group. So, once again, that's where we're looking at kind of region to region studies.

It's been mentioned by several of the panelists, the Southeastern Interregional Participation Process. Last December each of the transmission owners filed our transmission planning attachment Ks under order 890, and one of the things that 13 transmission owners in the Southeast stood up was a new stakeholder process for stakeholders to identify each year five studies to look at kind of what if we moved this much power say out of SPP into the Duke system. Or what if we moved this much power from the Entergy system into PJM. So, that process is new, it's under way.

Southern Company hosts the website and it has, if I get this right, southeastirpp.com . There you can follow the work that we've done. We've had two meetings with stakeholders. The most recent one in Charlotte in early July where the stakeholders have identified the five studies that we will do between now, and our schedule calls for the final report to be completed somewhere in the May '09 timeframe. With, you know, stakeholder updates along the way.

And the last thing I would mention is, once again, under the CERP umbrella, one of the things that the CERP long-term study group will be doing-- actually I have two more things to mention, I'm going to mention this one-- CERP long-term study group is going to be looking at an alternative generation scenario that will go into the NERC 2009 long-term resource assessment. And that scope is being finalized. But it will look at an alternative generation scenario for companies within CERP. I believe the study here is going to be 2019. And they will be looking at kind of variations on generation, on variation being the scenarios around additional nuclear.

So that's an assessment that will be done through that process. And it-- I believe the plan is to formally include it in the fall '09 NERC assessment. I think we should see the actual study work completed sometime in the spring of next year, is the target date.

Finally, I have to tell you about the North Carolina Transmission Planning Collaborative. It too has a website, nctpc.org/nctpc. But this is an open planning process that Duke and Progress Energy in the Carolinas use to plan their transmission systems. It's very much along the lines of the things that were spoken to in order 890. It's a stakeholder driven process. We begin that planning collaborative in 2005. And each year that planning collaborative produces an annual plan. So, if you go to the website, you can find the 2006 plan, and all of the appendices. You can find the supplement to the plan. And the same thing for '07.

I would say to the point that was made by Nathan, one of the things we do do with our stakeholders in that planning collaborative is we will through the year update them on where are all the projects that were in the plan. So we had an '07 plan and it called for 12 or 15 projects. We'll update them as to where they are, you know, are they being built, are they on schedule, have we seeing something in this year's planning process that suggests that project may be no longer needed. So, we do make that part of our active involvement with our stakeholders. Thank you.

David Meyer: Very Good. Thank you. Next we have Terry Huval.

Terry Huval: Good morning. My name is Terry Huval. I want to prepare the audience and our listeners for an accent change from Southeastern accent to south Louisiana Cajun accent. I'll try to speak slowly enough so you can understand me.

Under the rest of the Lafayette Utility System and Lafayette Louisiana, and I thank you for inviting me to be part of this panel today. Lafayette is probably the smallest of the entities represented here today. We serve 60,000 customers and own 741 MW of generation. Our cost structure and service reliability to our customers are regularly threatened by transmission congestion.

I want to make three important points to you this morning. One has to do with post-Katrina and transmission congestion in Louisiana. The second is to offer two additional metrics we'd like for the DOE to consider for the next congestion report. Then I want to make a comment about the value of transmission ownership.

I'll start off with the affects of Katrina and Rita, and the problems with the congestion still taking place in Louisiana. While there was some suggestion in the 2006 report that perhaps the congestion might have been relieved some by the affects of the hurricane, unfortunately, transmission congestion in Louisiana is still alive and well.

In Lafayette, since the hurricanes, we've shown a total of 206 TLRs, of which 138 were level four or higher. And just this month, in July of 2008, going from the first to yesterday, we've had 23 TLRs declared at levels four and five, basically split between the two. In one day we had three separate TLR 5s declared that affected our generation dispatch.

Many of these TLRs forced Lafayette to replace the use of low-cost generation with high-cost units to the tune of over $3 million in direct cost to our customers. Unfortunately, our experience is only part of the story. As there are many more TLRs impacting our state, and as such the hurricane did not relieve our history in Louisiana of transmission congestion.

But focusing closer to DOE's purpose today, I offer two new metrics for consideration. With the first being to address the magnitude of required transmission upgrades relative to transmission size. So, in addition to the current look at the percentage of transmission surge requests that are granted or denied, congestion analysis should also look at the cost of the upgrades that were deemed necessary to allow a transaction to take place.

I'm going to give you a specific example. Lafayette recently submitted a request for five-year firm transmission service for 25 MW on the Entergy system. We're served in our area with the Entergy system being the dominant transmission provider and Cleco being also another transmission provider. We were told for 25 MW, we were told it would cost to us between $112 million and $384 million in transmission improvements to grant our mere 25 MW request. At the high-end, that works about $15,000 per KW, which is multiple times the cost a new nuclear capacity.

There are things that we've done in recent times, discussions that we've had with the other transmission providers, I will discuss in a minute about some positive efforts in that area. But just to show how serious the problem is now. The second metric we would propose is to address the reliance on third-party re-dispatch for transmission system security. And this is what a deal we could consider whether and how often a transmission owner relies on generation dispatched by other utilities to keep its system within operating limits.

We understand that it's not practical to build a transmission system that allows least-cost generation dispatch under all conditions, but we also believe that it's not right for a transmission owner to design a system based on the explicit assumption that other parties will re-dispatch their units and absorb the costs to keep the transmission owner's facilities within limits.

After over five long years in our area, we appear to have reached a joint solution involving all the parties that will result in new transmission over the next five years. But after ten years, that will be ten years total of dealing with this particular issue, and my point is, good transmission planning by company A should not include the assumption that company B will re-dispatch its generation and swallow the cost to manage congestion on company A's systems.

My last point, I believe goes straight to the heart of the problem that we have discussed. You know, we all recognize that the power business has changed significantly over the past years and how power is bought and sold. But transmission is still largely a monopoly in a vertically integrated companies. Those companies that generate power and distribute it to end users, with many of those companies having merchant generation affiliates.

So within a single company, all these three-- all these different business units compete for the-- for a piece of the limited pool of capital investment dollars. Based on our observation, apparently transmission doesn't do very well in this context in some places. And maybe the profits aren't as attractive to Wall Street as-- transmission to us seems like not to have gotten the dollars it needs to keep pace with growth.

With some transmission operators having networks that are averaging 40 years old, facilities may be getting closer and closer to the edge of safety and reliability. I believe that if we're really serious in the U.S. about dealing with congestion we need to change the ownership paradigm. Stand-alone transmission companies are one option that seems to be working in the upper Midwest. Another option is to require that transmission owners allow joint transmission ownership, giving interested transmission customers or transmission-dependent utilities an ownership stake in the grid in return for their investments.

We also recognize that DOE is not in a position to force these changes, but we believe that these changes are a necessary part of the solution to the problem that Congress instructed the DOE to explore. The DOE's next congestion report might be a good place to get the ownership issue out on the table where we can start a serious dialogue in this context. Again, I thank you for inviting me to be a part-- with you today and for allowing me to participate in this very important process.

David Meyer: Thank you. And next we have Ron Carlson.

Ron Carlson: Let's see how Mr. Sullivan's trick mic works here. Thank you, David. Good morning. My name's Ron Carlson. I'm a project manager for Southern Company Transmission, Transmission Planning. And I appreciate the opportunity to be here today and to participate in the regional workshop sponsored by DOE as it prepares for its 2009 congestion steady.

Southern looks forward to providing whatever assistance may be needed to perform the 2009 study and will submit further comments as deemed necessary in the future. For today, I would basically like to touch on two items. A lot of it's going to be tied into what Mr. Bartlett, Nathan, had said earlier. But it's going to have some additional items in there as well, but for the first two, the 2006 study results and action taken by Southern Company since 2006, and the preparation for the-- as DOE prepares for the 2009 study, studies of interest as Ed and also George pointed out.

And in the 2006 study, Southern nuclear expansion was identified as a potential conditional congestion area. Since that DOE identification, Southern Company, along with other transmission owners in the Southeast, has studied both individually and jointly the potential of the addition of significant nuclear generation. That's, I guess planned or expected in the Southeast. Specifically, Southern participated in interregional liability joint planning studies with Duke Carolina, Santee Cooper, South Carolina Electric and Gas, Georgia Transmission Corporation, and MEAG to investigate the transmission impacts that nuclear expansion in the Savannah River Basin and the surrounding areas.

As part of the study, transmission limitations were identified and enhancements were identified as a result of those limitations. In particular, the joint study emphasized the development of interregional solutions that provided a least-cost solution over a single-company solution as part of those studies. So we didn't just look at planning for our own control areas, we also looked at planning for both-- multiple control areas that that was the least-cost solution.

Southern Company has also participated in the evaluation of potential nuclear expansion with TVA, FP&L, and Entergy, so we basically not only plan for our own nuclear generation, we also plan with all our neighbors to assess the impacts of those new potential nuclear generators.

Furthermore, as part of the 2009 long-term viability assessment, requested by NERC, as Ed mentioned earlier, CERP will be assessing nuclear expansion in the Southeast to ensure that sufficient transmission is being planned to support that potential nuclear expansion. And basically that's going to reassess what we've already reassessed individually and also as part of reliability assessment studies.

One more-- one much more near-term-- excuse me, on a much more near-term basis, the Southern Control Area has taken actions to address two of the historical constrains identified in the 2006 study. The Southern Control Area has placed into service a 35-mile, 500 kV on the north side of Atlanta that will help address service to Atlanta. Also, the flows from TVA to the Southern Control Area. That was referenced in the 2006 study. That line was placed in service in 2007.

Concerning Atlanta, Southern has also commenced the construction of additional generation within the metropolitan area as Commissioner Meyers pointed out earlier. It's essentially a re-power of an existing coal plant. From 500 MW up to 2500 MW. And the important thing to note there is you're placing generation close to load. And, in fact, you know, reducing the potential for congestion that may arise if you're bringing in power from long distances.

With regard to other significant transmission developments within the Southern Control Area, the Southern Control Area has two additional 500 kV lines to be placed into service in the next six years. One in 2010, that's 38 miles in length. And one in 2014 that's 48 miles in length. So, also, there is, I guess, looking out as far as the nuclear expansion plan is involved, plant Vogel as Commissioner Myers mentioned earlier, there is a third of 500 kV line associated with that generation if it does come to fruition.

The 2006 study also noted that Southern to Florida interface is a historical congested path. However, since 2006, the Southern Control Area transmission owners have offered incremental service across that interface. And additionally, a recent study provided to a customer could expand the Southern to Florida interface to as much as 5100 MW, which is quite substantial given the normal, I guess, interface amounts that you see across the nation. And even if you regard the 3600 that is current, it's a rather substantial interface.

Another significant development since 2005 in the Southeast has been the development of the Southeastern regional transmission planning process. And also the CERP process I had alluded to earlier. While the Southeast has sometimes been criticized as not being sufficiently transparent, the attachment K process, you know, kind of laid out in the order 890 issued by FERC last year, provides stakeholders with insight into the annual development of the 10-year transmission base case, the different assumptions and data inputs that go into those base cases, and the transmission plans that arise from all that data that goes into the models.

In addition. this process provides stakeholders an opportunity to have transmission providers in the Southern Control Area to perform economic transmission evaluations so they can see what kind of transmission projects may be necessary to increase the transfer capabilities that currently exist.

Furthermore, the Southern Control Area also coordinates with surrounding transmission providers, as I talked about a few minutes ago, through the Southeastern Interregional Participation Process to address such hypothetical study results that are interregional in nature.

In regards to the 2009 congestion study, while preparing for the study, DOE should consider referencing the following data. Regional EIE 411 reports. A gentleman from the Hartford, Connecticut meeting, I think, suggested similar data. But the EIE 411 contains regional loads, transmission resource data for a particular region, resource data in the 411 is identified by fuel type, which could be used as a merit-order stack for performance analysis. Dispatch and generation could be based on this, I guess, relevant fuel scenarios, high gas, high coal, vice versa.

Regional near-term and long-term reliability assessments which were referenced earlier. I won't go into a lot more detail because I think they've already been explained. TSR study reports. Such as the expansion-- the transmission offers that Southern has recently made, and I think some of the four other utilities have as well, to expand the Florida interface. It may be of value to DOE in doing their congestion study. ERAG load flows, I think were mentioned earlier by Ed as well. Those will be a good basis for doing the modeling of the congestion study.

And additional, I guess as Terry pointed out just a few minutes ago and the other panelists alluded to, is the Transmission Loading Relief Logs. In particular, I would focus in on the level fives and above. Showing where services being curtailed as a possible indicator of congestion. TLR logs represent real-time congestion that has occurred over the transmission system. In particular, DOE should look at those level five TLRs.

In addition, as part of doing the congestion study and looking at moving power I would suggest that DOE do, I guess, in their economic analysis, consider the transmission service rates between control areas and make sure that those are, I guess, identified as far as cost to move power. Thank you very much, Dave.

Dave Meyer: Thank you. Next we have Jennifer Vosburg from NRG.

Jennifer Vosburg: Thank you. My name is Jennifer Vosburg. I'm the Director of Regulatory Affairs for NRG Energy's South Central Region, which has four generating units in Louisiana. The larger of which is our Big Cajun II facility. It's a 1700 MW coal facility located in New Roads, Louisiana.

We are transmission dependent upon the Entergy system. In addition, we have the wholesale provider to 11 co-op customers in Louisiana and operate a control area for both generation and load. Like my colleagues before me, I would like to thank the Department for hosting this workshop.

In our focus on congestion issues NRG South Central region has been focused on congestion issues more recently and would like to follow up a little bit about the TLR discussion we've heard already today. We've already taken the liberty of looking at the NERC TLR log. I wanted to provide a little bit more specific information, just so that you can have a better feel and understanding of the impact that this is having in the Louisiana and Entergy region.

In 2007, the Entergy ICT issued 29 level five TLRs-- 47,000 MW of firm transmission service was curtailed. Other MW, Louisiana Generating had 7,000 MW curtailed. This represented 18% of all level five TLRs called in the eastern interconnect in 2007 were in the Entergy region.

In the first five months of 2008, in January through May 2008, the Entergy ICT issued 17 level five TLRs-- 42,000 MW of firm transmission has been curtailed through May of 2008. Of this, Louisiana Generating had 14,000 MW of firm transmission curtailed. The Entergy TLR through May of 2008 represents 21% of all level five TLRs called in the eastern interconnect in the first five months.

Terry also mentioned third-party re-dispatch. Again, to provide an informational-- additional information on that, in 2007 the Entergy ICT directed the re-dispatch of 2933 MW of network resources in the Entergy system. Through May of 2008, the Entergy ICT directed the re-dispatch of 16,093 MW-- 3,856 MW of that were lodged in network resources to be re-dispatched.

We strongly encourage the DOE to spend some time on the NERC TLR web looking at the TLR data and the logs that are there. We also strongly encourage the DOE to look at the reports of the Emergency Energy Alert Three, the EA3s that have been filed. An EA3 is a report that's filed when the balancing authority is incapable of satisfying its reserve requirements. An EA3 report indicates that a balancing the authority was short energy and that a contingency could result in it shutting firm load. Again, NRG has attempted to go in and look at the EA3s that have been filed.

In 2007, there were 18 EA3 emergencies called, and from our review of the documents it appears that most, if not all of these 18 EA3s are work related directly to an Entergy TLR. Through June of 2008, there have been 7 EA3 emergencies called, and again from our review it appears at least three of these were related to an Entergy TLR.

It is important to note that while TLRs were mentioned in the 2006 congestion study, the numbers do not reflect the magnitude of today's problem. The NERC data indicates that prior to 2007 Entergy called no more than nine level five TLRs in a single year. And between 2000 and 2006, Entergy called a total of 25 level five TLRs as compared to the 17 TLRs through May of 2008.

Again, to echo something that Terry mentioned earlier. The 2006 congestion study recognized there was significant congestion in Louisiana. But then noted that the information was based on pre-hurricane information, assuming that a reduced load-- congestion issues would also be reduced. Of the 11 NRG-- the 11 co-ops Entergy serves, many of them were directly impacted by the 2005 storm, and our data indicates that not only is the load of our co-op customers back and returned to pre-hurricane levels, in many cases that load exceeds pre-hurricane levels.

Other items that we would encourage the DOE to look at, we echoed the ISTEP plan that was issued by the Entergy ICT. We reviewed. It has concise information on the different upgrades that should be looked at and the flow gates that are impacted. Keep in mind though that ISTEP has no budgeting associated with it. So, at this point it appears to be more of a wish list than an actual planned budgeted upgrade.

We'd also encourage the DOE to look at the ICT FERC docket, it's ER051065. I believe that would be a good source of information as well on some of the problems that the stakeholders in the Entergy region have been experiencing.

It was mentioned earlier to look at the system impact study, so we'd also encourage you to look at the facility studies that are publicly available. I believe that the facility studies up until recently have contingency performed by Entergy and not the ICT so that would be something to check.

Again, we thank you for the time. NRG is willing to work with the DOE in providing any additional information. We will be filing formal comments in this matter.

David Meyer: Good. Well, thank you very much for some interesting commentary. These several references to regional planning processes of various kinds, principally under-- or in response to order 890. Tell me a little more about that. In particular, how are the scenarios to be analyzed? How are they devised? That is, is there a sort of a broad multi-constituency steering group that's set up that advises how these are to be framed and what some of the critical assumptions are going to be and things of that kind?

What I'm thinking about is one group that carves out what are the scenarios to be done, and what are some of the basic assumptions, and then another group that is sort of people who will make the process-- make the modeling stuff work and go forward.

Unidentified Participant: Yeah, I guess real high level, the stakeholders identify what scenarios they want to be, I guess, evaluated.

David Meyer: But they are principally corporate folks, or do NGOs get involved, or are the state commissions involved or--

Unidentified Participant: Yeah, any-- I guess-- the way we have the stakeholder behind that's basically the end user of the transmission system. So states can be involved, you know, as far as regulating for retail rate payers, that invest in our utility. We have a pretty broad mix.

I think we have, you know, let's say power markers, generation owners, generation developers, transmission point-to-point service customers, it really covers the whole array. But there's stakeholder group that uses the transmission system, including TDUs, to develop what economic studies they want to evaluate as part of that year's evaluation process.

Then through coordination with the stakeholders and the transmission owners, a set of assumptions are made. You know, as far as whether or not you're doing a generation to generation shift for those that do that type of technical analysis or you have to load the load shifts in all this. But all those assumptions relative to how you do a particular study are coordinated with the stakeholders. That's where you get into the kind of the details of the planning criteria between regions and all that stuff gets discussed as well.

David Meyer: But is there a-- my sense is that frequently the menu of possible studies, the studies of possible interest, the menu can be very long and can exceed the, you know, the man hours, person hours available to do the work and so some kind of sifting and sorting of what is the really important ones to look at and how is that sifting done?

Unidentified Participant: It's done by the stakeholders as well. It'll surprise you, you know, you might, for instance, we might of had had 15 or 20 requested studies. We're doing five. And through interactions with the stakeholders in a June meet we just recently had, we were able to kind of consolidate those down because similar requests were on the same path so it was pretty easy to combine some to get it down to the five level. There was basic paths let's say in the eastern interconnect that stakeholders are using the transmission system are interested in from time to time. So, that's the ones that appear.

David Meyer: Anyone else want to comment on this question?

Ed Ernst: This is Ed Ernst with Duke. The North Carolina planning collaborative that Duke and Progress participate in basically has three groups-- really four. There is a planning working group, PWG, is what we call it, and that's where the engineers do the actual detail analytical modeling and studying, okay? And we have engineers from Duke, Progress Energy, and then from our North Carolina municipals and our North Carolina cooperatives.

And those four entities are the ones who sponsor the planning collaborative. So the plant power flow working group builds the models, does all the detail analytical work. They get general direction from an oversight steering committee which is comprised of Duke, Progress, and the municipal co-ops. So they define the preliminary study scope scenarios and then that goes to overall the stakeholder group. Transmission Advisory Group is what we call it.

That Transmission Advisory Group will meet four to five times through the year and, you know, somewhere in the spring time they will settle on alternate scenarios they want us to look at. You know, typically we're going to look at a 5 and 10-year out view in terms of ensuring that the load on the Duke and Progress systems can be reliably served by the folks who want us to look at what if situations like, “What if we brought in this additional generation or had a dip in supply?,” we'll look at that.

So the stakeholders are the ones who identify those alternative scenarios. And then we, you know, we turn that around and review those preliminary results in the fall and produce a final plan at the end of each year. So it's a stakeholder driven process.

I'd say both Ron and George and I mentioned this Southeastern IRPP, this new interregional process that these large "what if" studies. Once again, that's a stakeholder group. You know, you've got regulatory folks there, you've got users of the transmission system, of the utilities. For example at our last Southeastern IRPP meeting, I believe we had someone from SPP there, we may have had someone from PJM there, so once again all those stakeholders helped us settle on those five studies and now we're kind of at the point of starting to do the detailed analytical work.

Ron Carlson: One additional thing to add-- this is Ron Carlson with Southern again-- is just because the stakeholder group requested certain economic studies, I would not say that that's an indicator of congestion. That's just a hypothetical that they're looking at. There are potential load serving entities going in new directions to get resources from, you know, areas in the future. So I wouldn't correlate the two together. It's just, you know, what they are, a hypothetical study.

David Meyer: Well, but it-- on a looking forward basis it, I guess that's the merit that is see in doing these studies, is that-- I see it as a vehicle for people to kind of come together and agree on what the regional problems are and what the different-- how the different solutions stack up and which ones ultimately are-- to go forward, whatever they might be.

Ron Carlson: The regional problem end of it may be a little bit strong. Like I said, I think it's more of an investigation to look for load serving entities or potential users of the transmission system to understand the capabilities that currently exist, and what can be done incrementally, you know, to move power across as far as the Southeastern IRPP process across a good portion of the Eastern interconnect. Because it is a rather expensive region.

You know, that information could be valuable for load serving entities within the Southern Control Area. To be able to take that information along with potential, you know, let's say if you're doing an RFP like Commissioner Wise and Commissioner Sullivan were talking about earlier, you take that information along with maybe bidders into an RFP process to determine what's the most economical future resource for native load in, you know, their respective states. That's where I see the value, you know, in during these studies for the end user of the transmission system.

David Meyer: Let me turn to the question of increased levels of trade or imports, and in some cases exports from somebody else's perspective. Particularly since say 2005 in some of the changes that we've seen in whether it's fuel prices or other, you know, economic development maybe in certain areas. Are there significant changes in flow patterns? Either do you see it happening now or changes that you anticipate?

George Bartlett: This is George Bartlett with Entergy. A lot has been said about TLRs on the Entergy system and I think those to a great extent result from the changes we've seen in flows on this system. The transmission system was designed to deliver energy from designated network resources to the load.

And to the extent that we have about 15,000 MW of IPPs on the system with cheaper energy then some of the designated network resources, and the fact that entities are all trying to avail themselves of that energy, it creates flows on the system for which it wasn't originally designed. And we have no control over that and as Ed Ernst pointed out, TLRs are an indication in real-time of what happens when the operators are trying to deal with these real-time problems of flows that are shifting on the system to accommodate these economic transactions that people try to put into place.

So we definitely have seen an impact, as people here have pointed out, on the Entergy system. And again, it's not from one particular unit, it's just from the mass of ICTs which are generating more energy now than they were back when you did the last study. So they are running, to a greater extent now.

David Meyer: And where does the planning process stand then in terms of evaluating either the severity of the problems or I mean I would assume you go through a kind of a stepwise process where first you decide, yes, there's a problem here but how significant is it, or is it likely to get worse if we don't do something about it? And then once you kind of got that-- got some calipers on it that way then you begin to say alright now if we were going to fix this what might we do about it?

George Bartlett: Again, we view these condition issues as economic issues not reliability-- because reliability is a whole other ballpark and it should be fixed to comply with the NERC and CERP requirements, the regional requirements.

But the economic fix is where the ICT comes into the picture. The ICT identifies areas of congestion on the system and they present possible alternative fixes or they're willing to work with stakeholders to develop those. And we leave it up to the stakeholders on the system, the customers of the transmission system to develop, or to work with us to develop plans.

As it was stated Entergy will do a facility steady to determine the cost of facilities that have to be built. We do that in conjunction with the ICT. But these are economic problems that we feel are best reviewed by the customers to determine whether or not the transmission solution to the problem is a feasible cost-justified solution. Because the transmission solution is not always the best alternative.

Jennifer Vosburg: Jennifer Vosburg again. Just to follow up on what George was saying, with the TLRs I believe another significant change that needs to be recognized is that the ICT is also attributing part of the cost of the increase in TLRs is that previously Entergy would voluntarily re-dispatch their units around the TLR and that process has stopped. And since that process has stopped I believe in either late 2006 or 2007, you have also seen an increase in the number of TLRs.

Just also on the follow-up on the economic fix with the ISAT again, Terry mentioned that the 25 MW and the cost, just to kind of fresh that up for you and give an example. You know, if you assume that a line is 100 MW overloaded and you come in, Terry wants to flow those 25 MW, the cost that was charged that will show up in the facilities study is not the 25 MW it costs to upgrade to 25 MW it's the cost to upgrade the system 125 MW. And that is an economic barrier that is occurring in the area where you're not seeing the transmission upgrades able to be developed because the economics do not work.

George Bartlett: Well-- George Bartlett with Entergy. I think we are seeing some improvements made as Mr. Huval pointed out, the ICT did coordinate efforts in the Acadiana area between Entergy, Cleco, and Lafayette to develop a solution to congestion in that area, so we have a long-term project going forward involving significant transmission expansion to relieve the TLR issues in that area. So I think the process going forward with the ICT should be able to resolve some of these issues that we've seen in the past.

David Meyer: In some parts of the country your colleagues are not in agreement, I would say, on that there is a sort of clear watershed between congestion from an economic point of view and congestion from a reliability point of view. That these things are more interactive perhaps than some of your comments would suggest. Does anyone want to comment on that, please?

Unidentified Participant: Well, I'll comment on that. You know, when you start getting into a situation where you call in a TLR level 5, you are cutting firm transactions that somebody had put in place and they were depending on that load or that generation or that source.

And, you know, we had a significant event that impacted us back in August of last year. That's when we set an all-time peak. We had a tube leak on a coal unit and were trying to get through until we got another unit back. And we were almost forced to a load shift situation or an emergency situation because of a TLR on a facility that we had that was firm.

So, I would argue that, you know, from an economic standpoint I know what they're trying to do here is say that it's, you know, where the dollars are spent and we're they're not, but if it's a problem in a base case on a planning model then it needs to be in a project identified and budgeted to get built.

David Meyer: Before we go on, we are almost to the end of our scheduled time for this panel but I'm told that we're not flooded with requests for statements from individuals, so if I'm going to keep this panel open and going as long as-- for a few more minutes, at any rate, because there does seem to be some fairly significant questions that people are interested in talking about, so let's continue and-- so, I interrupted you.

Terry Huval: Thank you. This is Terry Huval from Lafayette, Louisiana again. I guess I was encouraged to hear of the work in Alabama that's taking place and the confidence there was with the commissioners concerning the robustness of the transmission system there and how they feel that that robustness has aided the economic development of that respective area.

And I think just the premise that is being considered that for congestion being generally economic-based versus reliability-based is hampering transmission to be built in the state of Louisiana and I think it is probably contributing to the difficulty that we might have as a state to be able to draw the type of economic development other states have had.

So this has certainly, you know, reliability and how we operate the utility system is very important, but how it spills over into the economic viability of our respective state is substantially more important and so that's why we encourage the DOE to look at all of the various metrics that can help to get their arms around what exactly is happening and to try to put the emphasis in place for the viability of the utilities as well as the viability of the economic development in our area.

David Meyer: Let me turn to the question of renewables. And as I'm sure you know, in other parts of the country, the linkage between prospective development of renewables or even existing renewables is very closely linked to transmission. So do you have anything to add to what was said in the previous panel about the prospect of renewables in this area related to transmission changes or needs?

Jennifer Vosburg: This is Jennifer Vosburg. I think whether it's a renewable or the 25 MW that Lafayette needs, the first step that you're going to have to do is get transmission. And if it's going to cost $385 million for a transmission upgrade to flow 25 MW of renewables, again you just want to go to the economics of the project. So transmission could be a barrier to the development of renewables.

George Bartlett: George Bartlett with Entergy. Again, Southwest Power Pool is undertaking a study to look at the delivery of renewables from the Texas Panhandle area. They're looking into delivering pieces and parts of it in all different directions down to ERCOT in Texas and up north and to the east. The CERP companies elected, rather than to look at some renewal project to focus more on nuclear, and that's the basis of the study that they're doing as a group, looking at what if we put nuclear into the Southeast. So they really focused on nuclear as opposed to renewables.

In Entergy's case we're looking at the potential for putting in a couple of nuclear units at the River Bend or Grand Gulf, we're not sure which would entail significant EHV transmission additions to accommodate the energy coming out of those plants. It's hard to believe anybody could put in a nuclear plant without having to put in a significant amount of transmission to move it. So that's what's going on in the CERP area really as opposed to maybe some of the other areas within the country.

David Meyer: It-- you've reminded me of something that I wanted to raise earlier-- that is my sense is that if you're adding substantial amounts of new nuclear capacity in this part of the region in this part of the country, some of that is going to end up being exported to outside the region. Or at least, it would lead to significant changes in dispatch across the region. And so I'm just trying to understand how that is translated into changes in the transmission system.

George Bartlett: George Bartlett with Entergy. In our case, we are developing plans for transmission to make the nuclear fully deliverable within Entergy. So we're not looking at exporting-- transmission requirements to export any of that energy. And again, it would be a significant EHV transmission line running across the system with interconnection points to make it deliverable.

Ron Carlson: This is Ron Carlson with Southern. To touch on both the nuclear and the renewables. First on the nuclear, as George mentioned, most of the nuclear, I guess, projects not all, that we've looked at have looked at pretty much staying internal to the controllers such as Vogel. But we have been involved in other studies such as Entergy studies as it impacted third-party through the NRIS process and percolate out in early 2003.

David Meyer: Do you mean that the nuclear output would essentially be used to displace higher cost generation within your system or within neighboring systems or?

Ron Carlson: No, sir. Just the impact of the flows of that incremental unit on the Entergy system serving their load, or whoever's load that resource is being planned for. The same way if we've done similar studies as far as our local units three and four with, as I mentioned earlier, Santee Cooper, Duke, SCAG. We've also participated in a number of studies with TVA and also with FP&L just looking at the impacts of those incremental nuclear resources on the flow patterns within the southeast.

You know, we get drawn into other, I guess, generation expansion studies as well from time to time, not necessarily just nuclear but also sometimes cycle generation or CP expansion because we always want to make sure our neighbors are aware of the planning that we're doing on our system and if we perceive that there might be impacts on the neighboring system will want to get them involved in that process as early as possible. And FERC's order 2003 has a, I guess, pretty detailed process for doing that as part of the LGIP.

On the second thing you were talking about as you mentioned earlier about the renewables we do have an economic study, at least one of the five that we're doing is looking at bringing, I guess, renewables down into the southeast as part of an economic evaluation. But it's important to note that our load serving entities, at least within the Southern Control Area, are pointing to nuclear expansion. Or other, let's say, internal expansion with inside the control area right now. And they're the basis of how we develop our ten-year expansion plan and how we-- at least set out a plan to integrate new resources to serve load.

Once they, you know, maybe as an outcome of this economic study or maybe some type of regulatory requirement in the future they might have more of a desire to go after renewables but right now I'm thinking that, as Mr. Wise said, there is quite a bit of uncertainty associated with renewables and what direction to go.

Ed Ernst: This is Ed Ernst at Duke. I would just echo a couple of things. One I think was mentioned earlier that Ron talked about the study that was done several years ago with Southern and Duke and others looking a scenario of nuclear build out and, you know, that's going to kind of be an input to this CERP assessment looking at alternative scenario in 2019. We do have one at the southeast interregional process requested essentially looking at moving a large block of renewable/wind from the Midwest into the Southeast.

And then I would say in North Carolina we do have a renewable portfolio standard. I'm not an expert on it, but we are working in our North Carolina collaborative this year at several scenarios. Once again to identify the stakeholders around, you know, what exactly gets served by a certain amount of wind on the coast of the Carolinas, a certain amount of wind in our mountains and see what kind of transmission impact that would have.

David Meyer: Okay.

Mike Brown: This is Mike Brown with SMEPA. We're looking at-- we've got a number of paper mills close and things like that that they're looking at expansion and those type of activities but we're also participating in NRECA's developing-- or establishing a cooperative for renewables and we're a found-- one of the founding members for that. That would give you the ability to participate in renewable projects elsewhere. But as Jennifer mentioned, those also would require transmission upgrades or, you know, you've got to cross those bridges and that is a hurdle against bringing in renewables from outside.

In the Southeast, as it has already been mentioned, the wind don't blow that much and it's kind of hazy for solar. I mean there's some activity but you're not going to replace anything significant with those projects. I just don't believe. So, we're also working with others in participation with nuclear units if we have the opportunity so.

David Meyer: Okay. Well, I'm going to declare this panel at the close, and we will invite if there are members of the audience who wish to make individual statements we would be happy to hear from you. I'll ask you to step up and you can use the podium and just identify yourself and go from there.

Pat Caufield: My name is Pat Caufield and I'm with NRG. One of the things I was thinking of when you're talking it might be helpful information source for the department to look at it is-- it may come from the CFTC Commodity Future Trade Commission.

I know that one of the themes with the-- it's not working very good-- one of the themes was being able to move cheaper generation to replace higher cost generation even it has to go over some type of a distance, and I'm a trader, and I do know that a lot of the markets are being impacted by congestion. And a lot of the market movement-- movement is power due to market regional price discrepancy is creating some.

Terry had mentioned a TLR in August of last year and it was largely created, I believe, by some price differences between Cent[ph] hub and NRG hub. There was just a lot of people trying to take advantage of this difference and as George said this system just wasn't designed to handle that type of a power flow. But you can also take a look at what's recently happened by looking at the hub. NRG hub is an actively traded hub, Cent hub is an actively traded hub.

You can get information from *The Watt* daily or the Intercontinental Exchange, the ICE, and I know that in speaking with Mr. Watkins at the CFTC they look at that very readily. But not so much just at the price but the breadth of the market. What type of market support is there, how many buyers, how many sellers, who is actually transacting? Because I think what you'll find, at least in the NRG region, it used to be the most actively traded hub in the Southeast. I don't think you can-- from my observation, I don't think you can say that anymore. As a matter of fact you can't even find a calendar '09 bid or ask out there right now.

And that's solely due to the fear of congestion within the region. So I think you can probably get some information from them as to what's happened with the market impact as to maybe get a little more information for a complete picture.

David Meyer: Thank you. Any others? Anyone else want to speak up? Let me ask the panel-- get back to my panelists here and see if they have any final comments they want to make before we declare the workshop closed.

Unidentified Participant: Sure. I don't live in this transmission world every day, but just my observation is that when you look at what it costs, especially nowadays to build new generation, and you look at what it costs to build transmission, and you divide that transmission cost over the number of kilowatt hours that ends up flowing through the system, transmission is still a tremendous, tremendous bargain. And to allow ourselves to get to a situation where we have congestion taking place to the regularity that some of us have experienced that, is just, you know, not appropriate.

I would encourage the DOE to really look hard at ways to encourage transmission, just like you would encourage interstate highway systems or other transportation systems to be in place. And I realize it's all in matter of paying for it, but there needs to be some mechanism in place that lays out that type of infrastructure that when you divide the costs up are so low in comparison to the benefits that customers across the board can receive so I encourage the DOE in this effort. And I thank the DOE for listening to us.

David Meyer: Thank you.

George Bartlett: George Bartlett with Entergy. I also want to thank the DOE for the work they're doing. I think it's great in identifying the congestion across the system. My preference would be to leave it up to the marketplace to determine whether or not they want to fund upgrades based on the information that they deal with every day. But without the identification of the congestion, they wouldn't know which way to turn. So I think it's a good thing.

David Meyer: Okay, well I want to thank the panel for some very insightful discussion, and we have to go through the transcript, and we have a lot of things to look for and absorb so thank you very much.