U.S. DEPARTMENT OF ENERGY

TRANSMISSION GRID STUDY WORKSHOP

ATLANTA, GEORGIA

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265 Peachtree Street NE
Atlanta, Georgia 30303

DATE: September 26, 2001

TIME: 9:05 a.m. to 3:07 p.m.

REPORTER: Diana Ramos, Certified Shorthand Reporter

I N D E X

Speakers (Continued):

P R O C E E D I N G S

September 26, 2001

(9:05 a.m.)

MR. CARRIER: I'd like to welcome you to the second workshop of the Department of Energy's National Transmission Grid Study. My name is Paul Carrier. I'm with the Department of Energy in the Office of Policy and International Affairs, and I will be moderating this workshop.

I appreciate that a number of you have come some distance for this workshop and we appreciate your interest and we look forward to hearing your comments.

I would like to note that this meeting is being transcribed and so we might have some interruptions every once in a while from the transcriber who is asking for some clarification. And I -- I hear -- I hear -- I see hands going up in the air already.

Is this a little bit better? Do I have to get closer?

UNIDENTIFIED SPEAKER: A little closer.

MR. CARRIER: Okay. The meeting is

being transcribed so we may ask you to spell your name or something later on when you speak.

I would like to note also I have had several inquiries already about the transcription -- making the transcription available, and we will make it available on our website probably towards the end of next week when we get it.

I'd like to go over a few details on how we plan on conducting this meeting. We will start with some brief introductory remarks from Jimmy Glotfelty from the Secretary's office at the Department of Energy.

We will then proceed to take comments from stakeholders on our study. As you know, we've identified six issues that we believe should be addressed in the National Transmission Grid Study. There are, of course, additional issues that may cut across these six issues and we hope that you will help us identify these as well.

The six issues that we're focusing on: One, alternative business models for transmission investment and operation; two, transmission planning and need for new capacity; three, transmission siting and permitting; four, reliability management and oversight; five, transmission system operation and interconnection; and, six, new transmission technologies.

Now, at this meeting we have representatives and DOE's consultants who will be authoring each of these six issue papers and they will be working closely with the Department of Energy to prepare our final report due by the end of December of this year.

These individuals are: Joe Eto from Lawrence Berkeley National Laboratory; Brendan -- Brendan Kirby from Oak Ridge National Laboratory; Dave Meyer, consultant; Tom Overbye, University of Illinois at Champaign, Urbana. We have, who I hope will be joining us shortly, Eric Hirst. He's also a consultant. We have Fernando Alvarado from the University of Wisconsin.

We also have several additional people from the Department of Energy whom I'd like to point out so that if you need help anytime today they -- they are here to help you. I have Tracy Terry from the Office of Policy down this way. We have Cathy Tripodi from the Office of the Secretary. We have Vernellia Johnson and Sara Nickels, who have been out at the registration desk. We have Zead Haddad and Vincent DeVito and Jim Powell and Terry Roberts.

The way we're going to approach the speakers, what I'd like to do is ask speakers to come up and give their presentation in the order that we received the registrations this morning.

I would ask that you summarize your comments and encourage you to submit more detailed comments on our website or if you have brought, you know, written comments with you, then that's fine. We'll take those.

It would be helpful to us, you know, when you do come up to speak, you know, to identify yourself for the court reporter and also to identify the issues that you will speak to because of the -- well, you know, we -- the limited number of people that we have signed up to speak and many of you want to speak on both the issues that we had identified for the morning session plus the issues that we've identified for the afternoon session, what we're going to do is we're going to take all the issues at once so if you wanted to take on the three issues that we had for the afternoon, that's fine, you can do that in the morning. Again, like I said, we'll take it in the order that you've registered so you can address any of the -- any of the issues.

I would ask, due to the number of

speakers that we do have, probably about ten minutes maximum for your presentation, and then we'll have an opportunity for our authors here -- study authors to ask you some clarifying questions.

UNIDENTIFIED SPEAKER: Paul, we're still having a little trouble hearing.

MR. CARRIER: Thank you. This will probably go for all of us. Keep the microphone up close.

I'd like to ask Jimmy Glotfelty now for some opening remarks.

MR. GLOTFELTY: Thank you, Paul. Is that good?

Thank you all for being here. My name is Jimmy Glotfelty. I'm one of your senior policy advisers in the Office of the Secretary of the Department of Energy and am one of the managers on the National Grid Study Project.

As you all know, this was one of the action items in the President's national energy policy. The Secretary, by December 31st of this year, has to develop a study and recommend where transmission bottlenecks are, identify transmission bottlenecks across the US, recommend ways to solve them, and determine if, quote, unquote, a national grid is necessary.

We have gone through a process for about two and a half months now to try and identify how we're going to plan this project. It began with meetings solely within the Department of Energy, with staff from Energy Efficiency and Renewable Energy, Fossil, Policy, Secretary's Office, General Counsel, trying to pool our resources and determine, have we ever done anything like this in the past and what is the best way for us to proceed, using our knowledge as well as getting knowledge and input from the general public and the stakeholders that have a part in this process.

We determined that there was a entity called CERTS -- I'll let Joe explain to you what it means, what the acronym is, but they had done a study for the Department of Energy. It's a consortium of five labs and 11 universities around the country specifically responsible -- or their specific charge deals with electric reliability and transmission.

We thought with the short time frame that there was already a mechanism in place, that that would be a great method to get this study handled and it would -- and we would manage the process to allow as much public input as possible.

Therefore, we have these meetings.

We're having three of them. We had one Monday in Detroit, which ended up being a teleconference, and this one. I think, from my standpoint, this is a great turnout, and we look forward to all of your comments. And we're having one on Friday in Phoenix.

We have ventured down this road with some people that I want to thank, specifically Ethan Brown from the National Governors Association. We can't do this alone. And we've developed a partnership with the National Governors, the Western Governors, as well as some other groups that we think are integral to this process.

And we look forward to your input. I know there are some officials here today from some of the public utility -- or public service commissions in the southeast and we want to thank you for being here.

We know electric transmission is a big issue right now with the FERC's RTO orders, fairly controversial down in the south, as well as the northwest, as well as the northeast, and we look forward to your input.

Let me say one more thing. We hope

this study will provide innovative ways to increase transmission investment, solve bottleneck problems. We might hit on eminent domain. Who knows? The Congress might pass us on eminent domain, on electric restructuring legislation, but we think we need to put forth a first-class product that figures out ways that utilities, independent transmission companies and whoever else wants to invest in transmission gets the tools that they need to start investing in transmission.

So we hope that you all will think outside the box. We encourage you all to submit comments on our web page and look forward to everyone speaking today. Thank you.

MR. CARRIER: Thank you, Jimmy.

MR. ETO: My name is Joe Eto. I'm a staff scientist at the Lawrence Berkeley National Laboratory. In that capacity, I manage the Consortium for Electric Reliability Technology Solutions.

This is a national lab, university, industry or cooperative, collaborative R&D activity that's conducting public interest electricity reliability research, both through the Department of Energy and also for the California Energy

Commission.

Two years ago, we were tasked by the Department to staff the power outage study team and our work in that activity led the Department to ask us to participate in this activity today.

MR. CARRIER: Thank you. What I'd like to do now is move to our -- those who have signed up to speak at this session. We will -- if you haven't signed up to speak, we still want to give you the opportunity to do so.

So we'll go through those first who signed up to speak, then we will probably take a break and then give others an opportunity to raise issues, make comments, who have not signed up to speak.

The first speaker will be Gary Schaeff from -- Schaeffer from MEAG Power. And I will ask you to come up to one of the microphones. Following your comments, we will ask some questions, I imagine, and we do have available an overhead projector if you feel you need that.

Following Gary Schaeffer, there will be Jeffrey Roark.

MR. SCHAEFF: I can see there's rewards and punishments for being early. I'm Gary

Schaeff with Municipal Electric Authority of Georgia, which we go by the acronym MEAG Power, and I'm director of transmission for MEAG Power, and -- but today I'm here speaking on behalf of the Large Public Power Council and not MEAG Power.

I'm afraid our comments aren't going to be quite as focused to the issues of these meetings as we would normally like. Given the short time we found out about this and the occurrences of the last few weeks, I'm afraid we had to put together something rather rapidly, but LPPC will submit more detailed written comments before October 10th.

LPPC is the Large Public Power Council. It's an association of 22 of the largest public power systems in the United States and we serve, directly or indirectly, approximately 18 million customers.

The member companies are publicly owned and locally controlled and the member companies own and operate approximately 44,000 megawatts of generation and about 26,000 miles of transmission line.

The benefits resulting from the reliable and cost-effective provision of generation, transmission and distribution service flow directly to our public power customers and the communities that they serve.

Concerning transmission policy and legal restraints on public power, the Federal Registry notice of '96 did not really make any mention of the role of public power systems and the transmission assets owned by these systems. Thus, we thought it was particularly important to flag certain issues of concerns to the Large Public Power Council.

The LPPC supports competitive wholesale power markets and open access and nondiscriminatory transmission service.

Public power systems have a legal responsibility to meet the energy needs of their native load customers. We must maintain and retain resources to ensure the capability to supply such energy. State and local law place requirements on public power systems that must be addressed.

Our transmission systems have been built specifically to serve our native load customers, and we oppose any changes in law or policy that would undermine our ability to use these transmission assets to deliver reliable and economically priced power to our retail customers.

Concerning private use, LPPC believes that any transmission policy must include reform of the private use tax rules.

Without resolution of the current tax restrictions relating to private use, restrictions on tax-exempt bonds could prevent public power from fully opening up its transmission and distribution systems for use by other users, it could prevent our participation in RTOs, and it hinders the ability of public power to invest in infrastructure upgrades to enhance reliability.

LPPC members cannot make a long-term commitment to join an RTO or provide open access transmission until these issues are resolved. Once we join an RTO, even on a short-term basis, we cannot issue tax-exempt bonds to finance new transmission facilities.

Violation of the private use rules can make our tax-exempt bonds retroactively taxable. And just for an example, MEAG Power has got approximately 3 and a half billion dollars of tax-exempt bonds that could be subject to violation of the tax rules.

Concerning reliability legislation, the LPPC believes that there is a need to clarify authority over transmission reliability requirements and standards.

Concerning transmission jurisdiction legislative proposals, the LPPC supports what's called FERC-lite, which requires public power entities to provide transmission service at rates that are not unduly discriminatory and requires the company's non-rate terms and conditions to be comparable to those required of the investor-owned utilities, as part of any open access policy.

We do not support unnecessary expansion of FERC jurisdiction over public power transmission or in any manner that interferes with our fundamental obligation to provide reliable and economic power to our ratepayers and owners.

However, absent private use reform, public power will be unable to provide open access transmission service due to the existing legal restraints. Therefore, our support of the FERC-lite concept is predicated on the removal of these legal constraints.

The LPPC does not believe that FERC jurisdiction needs to be expanded to cover the transmission component of our bundled retail sales.

Concerning regional transmission organizations, many LPPC members either are already participating voluntarily in RTOs or ISOs and others are working hard to establish RTOs.

On a very basic level, we endorse the notion that coordination of transmission can have extremely positive benefits for consumers, but we also understand that every region, even some smaller subdivisions, can have different needs and problems. We advocate voluntary RTO memberships.

In Georgia, for example, we have an integrated transmission system which MEAG is a member of, along with Georgia Power and two other non-jurisdictionals. It works very well, in our opinion, but there are extreme difficulties on working that into the concept of an RTO without a lot of effort.

The LPPC believes that regional transmission organizations should have an appropriate geographic scope, preferably be not-for-profit, and, in all cases, be fully independent of market participants.

We strongly urge that RTO formation proceed carefully and without a one-size-fits-all approach.

The LPPC opposes granting FERC broad new authority to compel transmitting utilities to join RTOs. However, we support confirming the authority that FERC asserted in Order 2000 to order jurisdictional utilities into an RTO on a case-by-case basis in order to remedy undue discrimination or anticompetitive conduct.

The LPPC believes that regional efforts to form RTOs and ISOs should be recognized and built upon. We have strong reservations as to whether the concept of four large RTOs currently under discussion is feasible, beneficial or workable at this time.

Concerning the incentive rates, cost-based rates, LPPC supports the continued establishment of transmission rates according to well-established, cost-based rate principles. Allowed rates of return should be sufficient to compensate transmission owners for the risk and costs incurred by increased use of the existing transmission facilities and reasonable costs to attract capital for the new transmission construction.

Concerning market-based rates, we do not support the concept of market-based rates for transmission service. Except for isolated circumstances involving the construction of merchant transmission facilities, there is no evidence of competition among transmission providers for wholesale or retail customer business and no economic justification for implementing market-based transmission rates.

Concerning negotiated rates, we believe the establishment of transmission rates through negotiations between transmission providers and customers should be permitted only when the customer has either or both of the two demonstrated alternatives: The ability to continue to conduct business without the proposed transmission service or the option to elect service under the transmission provider's cost-based default tariff, similar to the recourse rate in natural gas regulation.

The ush of -- excuse me. The use of negotiated rates may also be appropriate when lining up customers for a new merchant or project-financed transmission facility.

Concerning performance-based rates, LPPC is willing to consider the appropriate -- appropriateness of a performance-based or other form of incentive rate for new transmission service. We believe the building of new transmission should be encouraged and believe that properly structured incentive rates might be able to encourage such investment.

An acceptable proposal could provide for a split-the-savings formula under which the transmission provider will be permitted to retain a percentage of the demonstrated savings achieved through the improved efficiency of operation, as compared to an accepted baseline cost of service, or through construction of new facilities that relieve congestion and lower transmission users' congestion costs.

Incentive rates must be nondiscriminatory. Incentive rates are appropriate only in the context of a filing by an RTO or subsidiary organization encompassing more than one transmission provider's system. Example, an independent transmission company.

The LPPC will submit more detailed written comments within a short time. Thank you. And I have copies of the talking points I just went over if you want them.

MR. CARRIER: Thank you very much. I'll take your copies. Thank you.

And what I'd like to do is give our study participants an opportunity to ask you some questions.

MR. SCHAEFF: Okay.

MR. CARRIER: What I'll do is just kind of go down the table in this direction and then this way and give everybody a chance.

Joe, do you have any comments, questions?

MR. ETO: No.

MR. CARRIER: Brendan?

MR. GLOTFELTY: I do.

MR. CARRIER: Okay.

MR. GLOTFELTY: Do you think postage stamp transmission rates -- if we were to have a southeast RTO, do you think postage stamp transmission rates would have a positive or a negative effect on investment in transmission, specifically by Large Public Power?

MR. SCHAEFF: I'm afraid you're asking a question I'm not certain of the answer, and I hesitate to answer it. We are studying that under the RTO work we're doing, but basically we haven't gotten to the point where we really know the answer to that yet. I'm sorry.

MR. GLOTFELTY: Another question. Do you all -- with certain tax restrictions that you have, do you think you are able to -- as municipal power providers, are you able to partner with merchant transmission companies now if you -- if you do not use tax-exempt debt?

MR. SCHAEFF: Yes, I think we could. There's obviously good benefits to our end-use consumers with the tax-exempt debt, and we don't want to jeopardize that. And realistically, today, under the existing temporary private use restrictions, we found ways to provide open access to the rest of the world currently. It's just under current constraints that we don't violate private use restrictions, but we have a open access tariff ourselves now. And I'm speaking for MEAG Power in that regard.

MR. ALVARADO: You indicated that you oppose market-based rates for transmission. Do you oppose market rates for transmission even as a component of congestion management, not as a primary rate, when it has been demonstrated in at least some systems that market-based rates are quite effective for the management of congestion?

MR. SCHAEFF: Well, again, I'm going to speak for MEAG Power's concept. Where we are right now in our current ITS arrangement, we have unlimited firm transmission rights to serve all our native load.

Even though we see congestion management type rates coming down the pike for RTOs, we have real concerns on what the possible impact is to us when we built our system, for the last 25 years, based upon unlimited ability within our territory to serve our load.

We've seen what happened in the northeast where congestion costs supposedly went up to like $200 million the first year they were implemented in a system that had no congestion before that, and that really worries us in what the impact may be.

So I guess we're concerned about it. We haven't really had enough study to analyze what the true impact might be, but we are very, very cautious concerning that issue.

MR. OVERBYE: I'm Tom Overbye from the University of Illinois. I represent the new transmission technologies area.

You mentioned that the four large RTOs may not be feasible. Do you see that as not being feasible from a technology point of view or some other point of view? Could you just elaborate on that?

MR. SCHAEFF: We're concerned that you're taking an existing system and sort of creating a new mega system with, in a lot of cases, a start-up company and trying to get it to manage and manage that system reliably. That gives us great pause for concern.

This is -- I don't mean to be -- you know, use scare tactics, but we're real concerned that you take a system that large and to operate it reliability -- reliably is a real concern.

As you well know, electricity moves at the speed of light. We've got systems now that work. In the southeast, they work very well. We're very happy with how the reliability systems are in the southeast and our customers have sustained no outages whatsoever for reliabilities problems.

Now to suddenly create a massive new system with, you know, technology to try to merge all that together under centralized control, that gives us some real cause of concerns.

We want to move into something like that carefully. We're not against large RTOs. We just think it has to be a very careful and well thought out process, that the reliability of our customers is not put at risk.

Can it be done? Probably.

Can it be done quickly? That's what gives us real cause of concern.

MR. OVERBYE: Thank you.

MR. CARRIER: Thank you very much.

MR. SCHAEFF: Thank you.

MR. CARRIER: Our next speaker is Jeffrey Roark and he will be followed by Phil Fedora.

MR. ROARK: I came prepared today to dazzle you with a high-tech presentation on the screen. At this point, you're just going to have to imagine that it was the best presentation that you ever would have seen, but what I'm going to do is actually just read a statement in lieu of that.

My name is Jeff Roark. My academic training is as a power engineer, and I've had 25 years of experience in the electric utility industry since, most of that in the regulated portion of the industry.

Today I represent the Mirant Corporation, which is a large international supplier of power. We have more than 21,600 megawatts of electric generating capacity worldwide, including 15,600 in North America and we have currently more than 9,000 megawatts under advanced development.

One of our concentrations as a company is on well-located capacity, and I would say that our major portfolios are located in D.C., New York, Boston, Chicago and San Francisco.

Our major comment's about the kinds of effort that you're setting out on that have to do with the way the transmission system is used today. The patterns of usage of the power system that we see today are, for better or for worse, products of the price signals that are in place today. We behave according to the price in the market.

Naturally we seek economic -- that is, economically efficient -- solutions to the physical problems that arise on the power system, but first we must recognize that prices for power and for the use of the transmission system are not yet based on the economics or the physics of power flow.

And it's very important that those matters be taken into account and the usage patterns that might change from that before we launch into a massive investment campaign in transmission.

If the prices for power at various locales across the country continue to be based on non-economic and non-physical principles, then further development of both the generation and transmission systems will reflect this inefficiency.

Generators will continue to be located in the most convenient locations for the generator rather than the most economic locations. And when I'm saying "economic," I'm saying economic for consumers as a whole, for the country.

More transmission lines will be needed simply to overcome the unfortunate location of new generators. There's some places in the country where this seems to be already happening. There are concentrations of generating -- generation showing up in places that now we have to build transmission to move it where it really should have been all along. Why did it go there? Because pricing was not there.

Transmission may be added to relieve constraints that are no longer binding by the time the lines are completed.

This last concern, that constraints may be relieved unnecessarily, is especially a concern if economics -- economic and physics-based pricing of transmission is introduced later rather than earlier, because this pricing alone may change the usage patterns enough to avoid constraining the system.

A quick story is we were evaluating

the -- or placing a value on capacity in the New York area. We -- we did congestion modeling and such and we did see the constant state of congestion between West New York and East New York.

However, when the real market came around, we still see those price differences, but a lot of that price difference is associated with marginal losses. Marginal losses are a real category of losses that we need to be concerned about.

If we're not looking at losses at the margin, then many of the transactions that are taking place that weren't taking place in New York, in our model at least, are not economic; that is, they cost everybody more money than they gain for the system or for consumers of electric power.

We are not looking at margin losses anywhere in the country and I think it's a very important thing to do to mitigate some of the congestion that's out there today.

If new plants, in response to better pricing, are located in the most advantageous locations, according to these better price signals, then those paths that are constrained today may not be binding at all tomorrow. Generation is an alternative to transmission.

I've seen a lot of comments that, for instance, our investment in transmission is not keeping up with load growth. Why should transmission investment keep up with load growth? They're not associated.

If you look at -- in fact, I think on the website, there was a statement that we kept up with load growth during the '70s and '80s, but in the '90s we didn't. Our investment dropped behind in transmission.

Well, during the seven -- from '79 to '89, there were 131 units added to the system who are larger in size than 500 megawatts. 26 of those were larger than a thousand megawatts. In the 1990s -- and that required a lot of transmission. In the 1990s, we added 33 --

MR. CARRIER: Can I ask you to get -- can I ask you to get a little closer to the microphone?

MR. ROARK: Oh, certainly, certainly. I'm sorry, I'm preaching. In the decade of the '90s, we added -- as a country, we added 33 units larger than 500 and only five of those were larger than a thousand, so it stands to reason that we didn't spend as much on transmission. There were many units added, but they were much smaller and they were located closer to the load, especially in the case of cogeneration.

We have alternatives in what we can do. We can rush out and relieve constraints that appear today, which is similar to adding lanes to an already overcrowded block of highway, which leads to more development and re-constrains the highway, without evaluating or understanding the physics and economics that should guide these decisions. Then we can hope that plant developer -- developers don't re-constrain the system. But if we don't put the price signals out there, they will.

Make pricing reflect the economics and the physics of power generation and transmission and then find economic solutions to the problems that remain. When new constraints appear and old ones arise again, then you will know that this is happening because it's the most economic thing to happen and not because of pricing fictions that we happen to be living with today.

We believe that FERC's initiatives to create large RTOs are oriented toward introducing pricing that reflects economics and physics to a much greater extent than is possible with the existing patchwork of jurisdictions and transmission ratemaking methods.

That -- that completes my statement. I'll be glad to answer your questions.

MR. CARRIER: Thank you very much.

Eric, I would like you to come up to the table up here so you have an opportunity to ask questions as well as the others. Thank you.

Joe? Dave? Brendan? Cathy?

MR. GLOTFELTY: I do.

MR. CARRIER: Of course.

MR. GLOTFELTY: I'll always have questions, I think. I've been kind of stuck on this concept of the interconnection process in the queue system, the queue being the -- I guess the waiting list for how we get interconnected to the transmission system.

Are there things that we can do or things that we might propose to revise the queue system or revise the interconnection process to encourage generators to locate in the correct place for transmission system from a transmission point of view?

MR. ROARK: Absolutely. I don't -- in my mind, the -- the interconnection issues are not the price signal that we need to be looking at. It's more the hourly price signal at the various nodes on the network. However, we are extremely interested in the interconnection process and making sure that the rules are consistent nationwide and that they make good economic sense.

We have to -- in both transmission planning and in interconnection, we have to recognize that we have taken one big system, one big machine, and we have split it in two. Part of that -- and as we used to plan it, we used to try to optimize the whole thing.

Now we're drawing a line in the middle and we're taking half of this -- the system -- I mean, it's a real system. We're taking half of the system and trying to -- to regulate that and price it correctly and the other side is going to be unregulated or market-based.

And so we have to be very careful how we make the decisions to optimize. And I still believe that attempting to optimize the whole thing is a good idea. If we -- if we try to optimize transmission alone, try to optimize generation alone, then we're all going to be spending a lot more money than we -- we really need to, and I don't think that's good for the industry.

MR. GLOTFELTY: Do you think -- kind of getting back to the queue system, do you think it's possible for us to recommend -- or do you think it's feasible for people to start thinking about streamlining that process --

MR. ROARK: Absolutely.

MR. GLOTFELTY: -- in locations that are -- that are better for the system, better for -- clearly right now most generators go out and find gas, water transmission and that's the place where they want to build a plant --

MR. ROARK: Exactly.

MR. GLOTFELTY: -- regardless of the cost for interconnection. If we can get them -- encourage them to go to places where it is best for the system, where minimal transmission upgrades, minimal transmission grids need to be built, could we streamline the queue system for them?

MR. ROARK: I don't think the queueing process is the tool that I would rather see used. I would prefer to see the energy pricing reflect the location properly, which can be done with congestion, with locational marginal pricing, including marginal losses which, again, for congestion, is an extremely important point.

That should be sufficient to take generators to the proper locations. The queueing process, on the other hand, is a problem. It's different everywhere. We deal in all areas of the country and so we have to deal with a lot of different rules.

But right now, you're right. It's the same process everywhere you try to locate, but I still would prefer that the queueing process be dealt with on its own rather than trying to get the location worked out with that.

MR. GLOTFELTY: Thank you.

MR. CARRIER: Anybody? Fernando?

MR. ALVARADO: Yes. I have two questions. Let me clarify -- first, just a clarifying thing in what you said. Let me understand.

You are actually advocating locational margin -- marginal pricing or a variant you call compatible locational pricing across the entire grid, whether it's separated or not, at least compatibly done. Is that correct?

MR. ROARK: Absolutely. I think different systems bordering on each other are going to create all sorts of seams problems. To me, the only way to get rid of seams problems is for that pricing to be consistent so we don't have a patchwork of -- of different things, different rules. There is one set of economics and one set of physics. I think we can decide on a method that puts the signals out there in a consistent manner across the country.

MR. ALVARADO: Okay. The second question. Let's assume for a moment that everything is now being done optimally, one LMP system throughout the country, there's still congestion, and, of course, the signals that you see end up encouraging generation in the right places, but because of the present barriers to transmission construction, transmission, although it may be the cheapest alternative to resolve many particular problems, still it's going to have many barriers to competing with generation appropriately because of the difficulties associated with the siting and issues like that.

So let me take you a step beyond. Let's assume now that the country has moved to your ideal system of economic pricing everywhere.

MR. ROARK: What I call Roark's World.

MR. ALVARADO: Now, what --

MR. ROARK: Is that what I call Roark's World?

MR. ALVARADO: Roark's world, yes. Let's move to Roark's World. And under those conditions, what do you suggest, recommend or propose be done with the transmission at that point?

MR. ROARK: That's -- that's a very interesting -- of course, it's a great question. It's a very interesting question that we spend a lot of time hashing about. I think this is one of the issues that I would like to see the industry try to solve correctly.

Probably the best system that I have seen for actually bringing transmission into a system guided by price signals was that of Argentina. Argentina had a lot of problems. And people that bought there, some of them lost a lot of money. We lost money.

However, it was not because of the rules to bring transmission in. Actually it was the lack of financial transmission rights in Argentina that were the problem. But the system in Argentina required that -- for transmission to be brought onto the system, the market participants who would be affected by it had to bring that in.

Now, that didn't mean that they had to invest the money. Actually, when it came time to invest the money, that construction portion, even the ownership and operation, went out to bid.

That shouldn't be a contestable thing. If it goes out to bid, then you may not even have to worry about -- about rates of return. You may be able to build in the return into the payment that your constructor, your owner and operator, agrees to build this transmission line and keep it in the air.

That system actually did work. It actually did bring the transmission capacity into the system. The problem was that with -- with -- without the financial transmission rights there, they were doing nothing to prevent additional congestion in the system.

MR. ALVARADO: A follow-up. If you were in a position to recommend to the government what they should be doing to facilitate this process which, by the way, you are in that position, what would you tell them?

MR. ROARK: I would tell them that that process in itself needs some careful study and examination. It is not a soft problem, it's hairy, and we need to put a lot of minds together to figure that out, but I do not think that it's -- it's insurmountable by the people in the industry today.

You have to think out of the box. You might have to think of somebody besides the transmission company owning all the transmission. You certainly might have to think of somebody besides the transmission company proposing and building a line because they have interests on the power side, but we can rationalize these things out.

I just -- I'm sorry, Fernando, I don't have a solution to recommend, but I think we could spend some time and put one together. And, as always, going from my experience with the Argentina system, that's kind of where I start. That one actually made rational sense, and I think -- I think Tabors had something to do with that a long time ago.

MR. ALVARADO: Thank you.

MR. CARRIER: Yes, Eric. Eric Hirst.

MR. HIRST: Jeff, then your comments focus on the importance of getting market prices like transmissions --

MR. ROARK: Yes.

MR. HIRST: -- to reflect both

congestion and losses?

The speaker before you, representing the municipal utilities in Georgia, appeared to take an exactly opposite view. If I heard him correctly, he said he opposed market prices. It's a little bit unfair, but can you reconcile those two views? Are you talking about different things or you just have different views on the same issue?

MR. ROARK: Well, I'm glad you asked that question because there is one thing I just want to quibble with there and, that is, actually using the term "market-based pricing" for transmission because I think that -- to me, that suggests something other than what it is.

The -- the problems that I hear with existing transmission users and existing transmission owners is that if -- if we go to a different kind of pricing system, then, gee whiz, I might -- I might have a lot of cost that I didn't have before, and that's not right.

Well, there are actually ways to deal with that. It's very important that -- along with pricing, that you have means to mitigate the risk of congestion pricing because once you show all those prices going up and down with -- with demand and with congestion, these things add risk to any transactions that are out there.

Those risks exist today, but if -- if you actually have to pay those prices, that adds risk. You need means to mitigate that risk. It doesn't have to be physical. These means can be financial and probably the world is better off if they're financial.

The sale of those, the allocation of those is a way to mitigate an overall shift in generation costs. Either the rights can be grandfathered to some current holders, in which case they would not need to suffer the financial harm of the congestion, or the transmission congestion rights can be sold off and then the revenues from those auctions can -- can be directed to those people who own the transmission or to -- or who have a stake in that -- that transmission situation.

There are ways around that. It's not a simple matter of if you go to LMP that everybody has to pay the LMP and that's the end of the story.

MR. ETO: I'm going to ask you a question to make sure I understand your position and its implication for the charge that we've been given in conducting this type of study.

If I understand you correctly, you're suggesting that just looking at today's constraints and attempting to relieve them may be inappropriate because the transactions that underlie them themselves may be uneconomic and so we'd be looking at the wrong problem.

And so what I draw from that, and I want -- I'm interested in having you confirm or disconfirm, that is, your suggestion really is to think more towards moving toward the larger RTOs and get a pricing system in place that would reveal what constraints might exist and only at that point, if there's not a, quote, market solution, to suggest a more direct federal role in attempting to address those constraints.

MR. ROARK: Yes. In general, that -- that's what I was saying. However, there's probably low-hanging fruit out there. I think there are some obvious situations, especially those that deal with reliability -- not so much congestion but reliability that could be found, could be dealt with directly.

Even some -- some congestion situations might be appropriate. They might be a low-hanging fruit -- sufficiently low-hanging fruit to go after those, but the assumption that if there's congestion, it needs to be mitigated, is false to begin with.

The systems were planned to accommodate congestion and we need to look at those economically. However, it's a lot harder to do now that we don't have entities that are optimizing the whole, they're optimizing only pieces of it, so if we -- if we price one of them correctly, then the other one can optimize in conjunction with the other.

So there's still a job to be done, but we think that pricing is an extremely important part of it. It needs to be -- at least needs to be considered.

MR. CARRIER: I have a question also. You talked in terms of optimizing the generation planning and doing that in conjunction with the transmission planning.

Now, these two areas, of course, have different forums in which the decisions are made, one being the market and the other one being more regulated. And I was wondering if you had any suggestions on how we can optimize the combination of the two planning processes.

MR. ROARK: The best that you can do

is make the pricing reflect the economics and the physics of the transmission system and then the market will optimize around those price signals.

The -- the market's going to operate according to price. Those prices need to be economic or else, as I said, the whole system in the country is walking off in the wrong direction. But if -- if the transmission side, which is the regulated side, is -- is priced correctly, then the other side will respond accordingly to the prices.

MR. ALVARADO: I have a follow-up.

MR. OVERBYE: We have follow-up.

MR. CARRIER: Can you use that microphone?

MR. ALVARADO: Jeff, you just threw me a little curve there. I thought I -- I would like you to -- some people have suggested and it's been said that in the market environment it's harder to separate reliability from essentially economic congestion issues, and at some point reliability becomes mixed into the whole pricing situation because if you have a reserve (unintelligible) and you hold back something for reliability, it has an immediate economic impact.

You know, would you like to -- care to

comment about the distinction or the similarities or how you approach the issue of reliability versus economy?

MR. ROARK: A very brilliant professor I knew at one time was working on working those reliability measures into the price, and it was very compelling.

We're not -- we're not actually there yet anywhere, but those actually -- those things need to be done. I think they are important price signals. However, I -- again, I don't think this is a -- it's certainly not an exact science at all.

But that's why I say the things that clearly need to be done, I don't know that we can scientifically decide what those are, but I think there is some low-hanging fruit out there that perhaps needs to be taken care of.

And those reflect -- those may reflect current imbalances in where the load is and where the generation is, and those would eventually go away by themselves, but we -- I think there probably are some things we just need to go ahead and look at doing.

MR. OVERBYE: I've got a quick -- I guess it's related to what Fernando said. On these low-hanging fruit, I'm having trouble understanding where in the system you can't balance -- you can't fix reliability with new generation.

Do you have some examples or are you just talking about distribution system issues?

MR. ROARK: Oh, I think in terms of transmission capacity, yes, it can be dealt with by generation, and that needs to be evaluated. There may be situations where you can't -- you just can't locate the generation in there. Maybe there's situations where distributed generation is appropriate, though.

So all of those things need to be -- need to be looked at. So, yeah. I -- I don't know. It's a good question.

MR. CARRIER: Thank you very much.

I would like to note that Commissioner Terry Deason from the Florida Public Service Commission has joined us.

And, Commissioner, I would like to give you the opportunity if you'd like to make any remarks.

COMMISSIONER DEASON: I'm right here. No, thank you. I'm just here to listen and to learn.

MR. CARRIER: Thank you for joining us.

Our next speaker is Phil Fedora, and he will be followed by John Pope.

MR. FEDORA: Good morning, everyone. My name is Philip Fedora. I'm the director of market interface at Northeast Power Coordinating Council.

If you're not familiar with Northeast Power Coordinating Council, which I'm sure many of you are, we represent the six New England states, New York and the provinces of Ontario, Quebec and maritime provinces in Canada.

I'm going to prepare -- I'm going to follow up my presentation with more detailed written commentary. Our mission is to promote the reliable and effective operation of the interconnected bulk power systems in northeastern North America through establishment of criteria, coordination of system planning, design and operations, an assessment of compliance with such criteria.

In the development of reliability criteria, NPCC, to the extent possible, facilitates attainment of fair, effective and efficient competitive electric markets.

The solution -- or the path to the solution of many of the issues that have been identified by the DOE will require the involvement and coordination of many parties. And in the case of NPCC, involve the appropriate Canadian entities and authorities.

I'd like to just comment on a few of the issues that were brought forth in terms of new technologies, transmission planning initiatives and reliability compliance and enforcement.

One of the observations that I could make was -- I can make is in the northeast at least there is a lot of planning activity underway. We recently concluded our annual general meeting in Toronto last week, where we had industry experts from American Superconductor, RETX, which is the Atlanta-based company providing for New England's application of their load reduction program, and representatives from New York and New England regarding the application of their respective FACTS devices at Marcy and at Essex in Vermont, which provided practical examples of using the so-called future grid technology right now in the northeast.

In addition, representatives from National Grid US, Transenergie US and NPCC staff participated in a panel session that reviewed the transmission planning initiatives currently underway at the company, regulatory, governmental and NPCC levels.

We also touched on the status of our reliability compliance and enforcement program and the recent northeast developments in terms of the northeast RTO formation.

From -- from our point of view and from what we can see, the activity and planning is pretty robust. Each control area has their own transmission planning initiatives.

In New England, they have a transmission expansive -- expansion advisory committee that has just recently proposed a plan that asks for input from all stakeholders. Individual company plans are available.

National Grid has a five-year plan that's out on their website that spans both New York and New England. Transenergie and others have proposed projects for the northeast that are incorporated in others' plans. There are several interconnection studies underway in the control areas that are coordinated between the adjacent control areas.

And, finally, at NPCC, where we assess the planning of these facilities to ensure there's no adverse impact between the regions or the areas through its task forces and working groups, have several initiatives underway, including the new regional planning forum which explores innovative approaches using new grid technologies to enhance the grid from a wide area of trans-regional basis, which involves not only NPCC members but our neighbors PJM on our borders.

What is most likely needed is expediting or -- the implementation or the development of the projects. There are certainly a lot of projects planned underway.

At a recent NERC meeting, they asked their planning committee to prioritize some of the recommendations that they are considering for transmission planning. Among the top were cost recovery and siting issues. Toward the bottom of the list was enforcement of standards and planning. I think that recognizes, from a large-scale area, where some emphasis needs to be put.

Although we all need to think globally, we have to realize that any action is going to be taken locally. And I would invite, as I have done before at the DOE post seminar in January in 2000, to join entities such as NPCC, to participate in our planning initiatives to help us, along with you, come up with solutions to some of the problems that you've identified.

Membership in NPCC is open and inclusive. And for public interest entities, there is no charge. With that, I would like then to say at NPCC we have implemented an enforceable procedure for the reliability compliance and enforcement program that will take generally recognized operating standards within the industry to maintain the integrity and reliability of the electric system.

I'll point out by enhancing reliability, this program will enhance competition by ensuring a more stable platform across which energy can be generated, transmitted, traded and delivered.

I'll just close my brief remarks today with a statement that our chairman, Charlie Durkin, had at our general meeting which, in part, said, In Order No. 2000, the Commission has stated that an RTO should be configured to recognize natural trading patterns so as not to erect unnecessary barriers to trade and recognize that, quote, natural transmission boundaries do not necessarily coincide with international boundaries, unquote.

A US Northeast RTO cannot alone accomplish the task of encompassing the entire natural northeast market due to the international character of the northeast marketplace. A common foundation of reliability criteria is needed in order to permit Canadian entities to interact seamlessly with the US northeast regional transmission organization.

And I would propose that NPCC provides the necessary reliability fundamentals and a fair and nondiscriminatory organizational structure to facilitate such interaction. The development, compliance assessment and enforcement of reliability criteria, which are the -- fundamental to the platform and operations of a Northeast RTO, are best accomplished through an international regional council organization. Thank you for your time.

MR. CARRIER: Thank you, Phil.

Anybody on this side of the table?

MR. MEYER: What's the level of participation in the planning process presently in the region? By states, state officials? Are they active participants?

MR. FEDORA: We have -- and you can go to our website to get the list of our latest membership, but the New York State Department of Public Service is involved, the Office of Henri

Rauschenbach in Massachusetts is involved, as well as the Quebec Energy Board.

MR. MEYER: So some do and some don't?

MR. FEDORA: It's a voluntary, open process and they're invited all to join, as we extend the invitation to DOE as well.

MR. MEYER: Okay.

MR. KIRBY: Do you see a need for or difficulty with coordinating reliability rules with neighbors?

MR. FEDORA: The question comes up as the seams issues between reliability councils and if you move to one large or several large RTOs, what would be the -- would there be then problems involved and differences in criteria?

Right now, the differences are not as great as one may think, and what you could find is by having an open process to evaluate what makes sense for the reliability criteria, you would develop the rules that are appropriate on a regional basis.

So by inviting more of the stakeholders and the interested parties to participate in the open process to develop those criteria, rules and standards, I think you'll get a stronger framework, just as they're moving toward, in the market side, to try to standardize the markets.

At one point, I read a message that if there was more standardized market design across the United States, maybe the need for four RTOs would be less important than eight or some number because it's really the rules and the mechanisms that are important, not so much the boundaries that are drawn.

MR. OVERBYE: Since I'm in the new transmission technologies, I would like to ask you a little bit about that since you did mention some specific installation, the FACTS locations.

Do you -- do you see FACTS as being able to solve a lot of our transmission problems? I mean, is this something you'd really like to see pushed?

MR. FEDORA: Well, what I'd like to see pushed is that the options that are available to the parties, flexible transmission, AC transmission, load reduction programs, price-sensitive load reduction programs, applications of new technologies, such as superconducting cable, or whatever the technologies are, that they are considered by the stakeholders that are involved in the process and that the benefits -- cost benefit analysis is introduced into their awareness so that they know these are options.

And from NPCC's level, we would like to provide that forum for them to investigate whether or not these applications -- if they are opportunities for them to use those technologies.

I wouldn't say any one technology, one size would fit all, but it's the evaluation of the availability of these technologies that should be considered, including some of the old new technologies, which include restringing transmission, re-phasing. Whatever needs to be done should be looked at from a new perspective.

So it's important, but it's not, I don't think, the complete answer. I also mentioned that HVDC, which is certainly not a new technology but of which NPCC has major interconnections, has been in place for quite a while, too.

MR. OVERBYE: Since you brought up HVDC, I've heard there's a project to bring power into New York and PJM and New England from Canada using a DC line on the seabed.

Is this -- is this something that we should at least be considering as new corridors in the ocean?

MR. FEDORA: Well, when you introduce the possibility of a lot of people in the process coming up with ideas, you'll find a lot of innovative and different solutions.

Who would have thought you could expand the network to the Atlantic ocean, but there are people that are willing to develop such projects, depending on how the interest is and the technical feasibility as such, so I think it's important to realize in the world that we're moving toward, transmission owners have a role.

The assessment of the plans at the NPCC level and the identification of opportunities are important, but the merchant transmission people are also very active in looking at ways that they can help, whether it's relieve bottlenecks or increase throughput or enhance the reliability network.

That's certainly one of the options that's being considered and studied.

MR. CARRIER: Tracy, you had some questions also?

MR. ALVARADO: I have --

MS. TERRY: Go ahead.

MR. ALVARADO: Phil, I have two

questions. The first is, in terms of planning expansion for transmission -- it's the same question I asked the previous speaker -- what role do you think the government should play -- the federal government should play in the transmission expansion process, particularly in terms of the inter-regional interconnections?

And my second question, I'll give it to you because they're related, is that you -- you mentioned that Order 2000 refers to natural and existing trading patterns. However, of course, the natural and existing trading patterns are a result of the existing transmission. So would those change if the transmission were to become more inter-regional?

MR. FEDORA: Well, I guess the answer to your first question would be to repeat the -- what you should consider is -- strongly consider participating at the local level. And, I mean, I know this study is based on a national basis in terms of local, in this case would be the northeast, for instance, and come to our meetings, join the organization, participate in the working groups and the discussions that take place to help get your point of view, as well as listen to the points of view of the other people, in an open and free manner. That would be one suggestion.

And the second question, if you could just rephrase it again for me. It was --

MR. ALVARADO: You know, the natural --

MR. FEDORA: Is it going to change?

MR. ALVARADO: The natural and existing trading patterns are, of course, a product of the existing system --

MR. FEDORA: Right.

MR. ALVARADO: -- and financial arrangements in place, that if you had a different perhaps more all-encompassing transmission grid, the trading patterns would be very different.

MR. FEDORA: Right. I guess anything I would comment on that is the only thing I know for sure that will happen in the future is things will change. So we need to develop a flexible approach to adapting to change and not being strict and rigid in the way our processes look at various options.

As we evolve, we'll certainly have to evolve in terms of how transmission planning will coordinate with the fact that there may be four RTO-type entities in the United States. You know, there should be time to evolve and adapt and see how those mechanisms may suit the new -- the new world.

I think what you have to look at is, does an organization have the structure in place to allow it to change and adapt as the world around it changes, and that's what we have at NPCC.

MS. TERRY: You mentioned that there was plans going on at a number of different levels, from an individual company level all the way up to the regional level, and I was wondering, how do you resolve any potential conflicts among different competing transmission plans?

Is it all done through a consensus stakeholder process or is there any institution that ultimately can say yes or no to any particular project or plan?

MR. FEDORA: Well, at the planning level, the plans are submitted to NPCC for assessment in terms of our criteria. And at that point, if there are adverse impacts to the plans that are submitted, they have to require the approval of NPCC membership to go forward.

It's one of the steps in the process. Prior to that step, it's through consensus building and through working at the working group levels. Getting areas that are identified as being problematic or need more work sends those plans back to the entities to come up with a satisfactory solution in terms of the reliability.

MR. CARRIER: Eric?

MR. HIRST: Phil, in your remarks, you said that, quote, the planning is robust, and I want to follow up on that a little bit.

The speaker before you, Jeff Roark, emphasized the possibility of generation subbing as a substitute for new transmission. Ross Malme later today will talk about the possibility of demand management as an alternative to new transmission. Jeff also talked about transmission pricing as a way to manage congestion.

To what extent are the transmission planning processes in the northeast expansive? That is, to what extent do they look beyond transmission solutions and look also at suitably located generation, demand management programs and transmission pricing alternatives?

MR. FEDORA: In answer to your question, one of the best sources you could refer to would be the National Grid's five-year plan, which looks at a whole range of options. It does not tell people what to do, but it gives people areas of opportunity where things are best to be sited, where things might be problematic to be sited, and let the market or let the people that are the stakeholders involved make those decisions as to what to do, but all of those that you mentioned are viable options that are considered in the planning basis and have to be considered as we move forward.

MR. CARRIER: Yes, Phil, I have a question as well.

MR. FEDORA: Yes, sir.

MR. CARRIER: The NPCC, of course, is an internation -- has an international area you cover, both in the United States and Canada.

MR. FEDORA: Yes.

MR. CARRIER: And I was wondering, in the -- if you could give us any insights or cautions as we move forward here as to any concerns with our interface with Canada.

MR. FEDORA: Well, we founded NPCC because our membership is 50 percent Canadian, 50 percent US. And as the 50 percent that is Canadian in NPCC, it represents 70 percent of Canadian load, because it's mostly on the East Coast of Canada, but they are quite vibrant and willing participants in the NPCC process.

It gives them a voice and a vote in the transmission plans, the criteria development, a voice to be heard and actually a way to weigh in on various issues.

One of the hazards is -- of any planning process, I think, is to exclude, either jurisdictionally or for other reasons, any entity that has a large stake in the outcome. And certainly Canada has a very keen interest in one of the markets that it's interested in playing in, which is the United States, and fair game, vice-versa.

So I think what we have to be aware of is to make sure the appropriate Canadian authorities and entities are in the loop, at the table, and are there to contribute to the ultimate decisions that are going to be made.

MR. CARRIER: One more question. The NPCC, of course, is a regional reliability council. We have talked about national reliability councils and we also have talked -- you know, FERC recently has talked in terms of very large regional transmission organizations.

How do you see these three different types of organizations interfacing with each other?

MR. FEDORA: Well, first of all, I

think there will probably be legislation sooner than later introduced that may resolve many of these issues right now, and I know there's a lot of activity at the present time trying to resolve who should be responsible for reliability, who should be responsible for the enforcement of the reliability criteria.

Everyone recognizes the importance of those issues. From our point of view, of course, we would believe that that would be best served, as my chairman said, by an international organization in the terms of NPCC, because of our heavily Canadian influence, that provides the open and inclusive membership to have them have a voice in that -- and if there are any sanctions or reliability concerns -- noncompliance to reliability concerns, that there's a mechanism there to help resolve them.

So I think between the region -- I think that will be settled out maybe within a short time period as to what the model will be going forward. I'm supportive of the fact -- NPCC is supportive of the fact of regional reliability councils moving forward to carry -- we have the structure in place, we have the membership in place and it's incrementally not a very large job to merge or incorporate as we move forward. It's not like starting from scratch.

MR. CARRIER: What about for transmission planning and the role that NPCC would play as opposed to the role of the RTO?

MR. FEDORA: The RTO's role is very important in terms of the developing and reconciliation of the many interconnection requests that they receive from the siting of new generation and from a bottoms-up approach, coming up with proposals for plans as they move forward, that are frequently reviewed as -- as things change, as well as interconnection requests and whatever.

NPCC's role historically has been the assessment of those plans to assure that there is no adverse impact from anything that may be done from, one, control areas or ISOs or RTO's point of view, either from a trans-regional or inner area perspective.

And I believe that will continue as we move forward with this process. No matter how many RTOs finally are developed, there's always going to be a boundary with another entity and there will always be the Canadian entities as a non-jurisdictional interface.

MR. CARRIER: Thank you very much, Phil.

MR. FEDORA: Thank you.

MR. CARRIER: I'd like to ask -- introduce at this time Commissioner Buddy Atkins from the South Carolina Public Service Commission.

And, Commissioner, I'd like to give you an opportunity as a public official to speak at this time, and I apologize for not catching you on my list earlier.

COMMISSIONER ATKINS: I would like to make a statement, just a minute or two.

And I'm going to speak up. I think he's turning up the volume for those of us who are hard of hearing.

MR. CARRIER: The Commissioner has been over there giving me all the hand signals on whether he could hear or not.

COMMISSIONER ATKINS: I do want to thank DOE and all the members who are participating in the workshop for the opportunity to be here today.

We, too, kind of found out about this last week and kind of hurried down, so I don't have any prepared statements, although I do want to try and make some remarks.

Let me couch those by beginning with a statement that what I'm going to say is just my opinion. It certainly does not reflect my fellow commissioners on the South Carolina Public Commission -- Public Service Commission or staff. It's just Buddy Atkins from Rock Hill, South Carolina talking.

I had the opportunity to go and participate in the FERC RTO mediation, if you could call it that, and I am a trained mediator, and it was a very interesting process. I think it accomplished a lot of things which showed us, like any good mediation should, where some of the holes are.

What I think I see in some of the papers -- issue papers that have been given out in the discussion today, I see some of the same issues recurring again.

And I guess my first statement would be to -- certainly to the extent possible, that DOE work with -- with FERC, what they're doing in terms of the RTOs to try and bring about, you know, more of an integrated approach from the federal government. I think that would be helpful for all the participants, and in particular the other state commissions that are involved.

I think one of the things, too, that would be helpful, too, I think that in our case in the southeast Judge McCartney came to the realization that there needed to perhaps be a special place for state commissions. We became a separate voting group.

I don't think any of the states, with the exception -- in the southeast, except for Arkansas, voted because of the implications of voting and taking a position in the mediation, but I think, as in that process, this process may benefit by having a greater dialogue at DOE with the state commissions.

Again, not speaking for my fellow commissioners or for my state in general but just from me, I think that our state should not act as barriers to progress in upgrading our transmission system or our bulk electrical system in general.

As a scientist and an engineer, former faculty member at NC State and the University of South Carolina, I've done a lot of modeling. I'm an environmental engineer, water resources engineer by training and have done a lot of work on demand side management using some rather recent optimization techniques that they teach a lot out at the University of Illinois, like simulated annealing and genetic algorithms and other things.

So I'm very much in favor of optimal control theories for siting and investments in transmission and generation. I think we have to better define the constraints in those so we can understand what's going on, but I think those things are doable.

But as in any test of alternatives, which I think this is, we have to look at the feasibilities of various alternatives, and those involve engineering for technical feasibilities. They involve economic feasibilities, financial feasibilities, institutional feasibilities and not last, and certainly not least, political feasibilities.

And I would note that -- that on the first handout y'all have on alternative business models for transmission investment and operation, that one of the issues on there is concerns with governance and regulatory oversight, something that state commissions are very much interested in that we believe is going to need to be solved.

And then last, we have the political

feasibility of alternative models. I think that's where the involvement and more closer working relationship with state commissions will come in handy in trying to resolve some of those things.

I think it's going to end up being a rather elaborate, elongated alternative dispute resolution process. And it's one that couches itself in orders and court battles, which it's probably going to do, I don't think we're going to get anywhere in a timely manner, but that's my mediation training speaking.

We would hope that the governance and regulatory oversight issues could be settled. And, again, as a state commissioner, we plop ourselves right down in the middle of not being in favor of an ISO or a TRANSCO or an ITC or whatever.

I think we're the last bastion, as is in all state commissions, of the protection of retail customers. And, again, while we should not prohibit or try and put off progress on a more regional or national scale, I think we have to take into account the basic ability of people out in our states to pay their bills.

An article today -- news article on Channel 11 about Atlanta Gas & Light and how they're going to have so many people cut off. Our main electric utility in South Carolina, we had a report at our agenda session yesterday, their earnings are down 200 basis points because of non-collections, because of the volatility that we had in the gas market last year.

What I believe cannot happen in this process is volatility in our electric markets like we've had in our gas markets. Now, I don't know how you resolve that. I am a regulator and have been a regulator most of my life except for my seven or eight years in acidemia.

I know there are tremendous inefficiencies in a regulatory environment, but there are a lot of good things as well. I know there are tremendous efficiencies in a market system, which is, again, on your alternative business models for transmission investment and operation handout. That's -- at the bottom of the page, it talks about market efficiency.

We need to be able to utilize and take advantage of market efficiencies, but markets are not perfectly efficient and we should not rely or put all our eggs in a basket of a perfect market efficiency.

One of the things that's disturbing to

me that I've heard so far is that there's this conception that the entire world is deregulated. Well, the southeast is not. And the folks who elect me, and I'm elected by the members of our general assembly, have decided that we're not going to be, at least for the foreseeable future.

Now, when they decide to tell us that the Commissioner passed a statute to do that, then we'll administer that, but I think it's incumbent upon us as commissioners to make sure that we protect those vertically-integrated utilities, help them interface with planning, with existing systems, whether it's NERC, SERC, a refined NAERO, an RTO that comes out in some type of an optimal setting, whatever that would be.

But we're kind of in a different framework, and we believe that the marginal benefits of deregulation may not be there in the southeast. We've got some pretty low prices. It can't go much lower.

If it is, it's going to be below cost, and hopefully we won't ever sell electricity below cost like we sell telecommunication services below cost.

The other thing is the idea again in

working with state commissions and the whole -- I think what's going to run into a little train wreck with the RTO process with FERC is this idea that you have in your transmission planning and the need for new capacity paper, which is the centralized versus decentralized transmission planning expansion.

And I would just like to go ahead and add generation to that because I think we're kidding ourselves if we don't talk about transmission and generation simultaneously, and we need to quit doing that.

We have some pretty good planning. We're one of five southeastern states that has a siting act that encompasses not only the environmental but a needs assessment for siting transmission and generation and whether or not and how it fits into overall system reliability and, importantly, what nobody seems to be able to define here, is system economy.

What's the best alternative? What's the least cost alternative, given the real constraints in the system that I mentioned earlier, technical, economic, administrative, political?

And I think that if anything comes out of this, there's going to have to be a new paradigm.

Again, not to be -- to try and stand in the way of progress, I think one of the things we might have to look at are some models that are in telecom, such as a joint state-federal board in a regional setting.

It cannot be advisory. It has to be true governance. And I know some people won't want to hear that, but I think that's the only way that it's going to happen.

You're going to have to -- for example, if we add a southeastern RTO, I think you're going to have to look out for the southeast, you're going to have to have input from state commissioners, maybe a representative from each state commission, who knows something about bulk electric systems, and then you're going to have to take that back and make sure it's consistent with state policy.

We don't want to have a load of merchant plants in our state, that has happened in Mississippi, to supply the rest of the world power, to use our error loadings, to use our water, to use our rural sites, to contaminate our transmission and cause undue congestion.

We want an idea of broader, more robust planning. And we think that it's there through integrative resource planning. And the disconnect here seems to be that in this rush to deregulate, although it's really re-regulation, is that we've forgotten about the idea of still trying to have some type of overarching planning, integrated resource planning.

That's what my fellow commissioners at NARUC say all the time, well, can we have deregulation, can we have regional systems, but why cannot we have a regional integrated resource planning type of a scheme to pull this off?

And I think that's what the gentleman from Mirant, if I pronounce that right, said, but clearly this is going to be a difficult issue. We, I know, look really -- look forward to working with DOE and FERC on this. We don't want to be an obstructionist party in this, but there are a lot of unanswered questions.

And we have to be able to respond back in our case in South Carolina to the members of our general assembly and to our consumers to make sure that whatever transpires, if it's non-optimal, if they get an additional ten-dollar charge on their bill every month, they're not going to come and march on DOE. They're going to come and see me and they're going to come see our legislators.

And we've got to find a way to talk about what these true costs are going to be and the true benefits, especially in the southeast where we have low-cost services and we have very reliable systems.

So I look forward really to working with y'all in this process and, again, appreciate the opportunity to be here. I'm -- like Commissioner Deason, I'm here to learn, but I just wanted to reemphasize some of the things that I said at some of the FERC mediations, and I don't think it's anything new that y'all have not heard, but want to reinforce those.

And certainly through this process, we -- we shouldn't, I guess, give up our ideals and everything here, but we're going to have to come to a well-founded consensus, one that's based on science and good engineering and does what's best for a majority of the folks in our region. And I appreciate it.

MR. CARRIER: I really appreciate you coming, Commissioner Atkins, and we recognize it is very important for us to work very closely with the states in conducting this study, and we'd appreciate the opportunity if you -- I think if you can hang around another couple of minutes, we might have a few questions for you as well.

COMMISSIONER ATKINS: Okay. Oh, I'm here for the day.

MR. CARRIER: That's terrific. Do we have any questions from this side?

MR. MEYER: Other than the nascent RTO, are there regional vehicles or existing regional vehicles where one can do broad -- do transmission planning on a broad scope and interstate -- from an interstate prospective or look at siting issues from a broad perspective?

COMMISSIONER ATKINS: Well, again, I am not an expert on the electrical side. Again, I'm a water resources environmental engineer by training, but I am a modeler so I'm familiar with a lot of the power models. There's similarities to water distribution modelings because they're all network models or some analog to that.

You know, I look to SERC. I brought my SERC annual report. If SERC is not some kind of regional planning group, I don't know what is. And clearly I don't know what's going to happen to NERC or NAERO and how it's going to fit in, but I think there's some well working existing models out there.

Now, obviously -- are there things we can improve? Yes.

It's problematic to me that we -- that every state doesn't have siting authority and some do. For example, we do. Georgia may not, for example. I think that -- if we're going to pull this off in a regional sense, I think we're going to have to have some type of a regional siting authority, and that's what I was speaking about in terms of perhaps having something to an analog of a joint federal-state board on telecom, do that for transmission and generation, say this is where we believe the least cost sites are for generation. This is where we can put distributed generation. Here's where we need the main links in our transmission system to up -- upgrade those. Here's the cost allocation scheme so that, for example, we in South Carolina wouldn't have to carry an undue burden in terms of what our consumers might have to pay for upgrades to transmission versus some -- some other state because of, you know, the -- a broader or greater development of a wholesale market in those states for generation.

So I don't know what the exact model is. I know there's some water resources analogs, Delaware River Basin Commission. Maybe that's not a good one, but that's one that comes to mind. Potomac River Basin Commission. We're going to have to have some type of a collaborative but one that has some authority with it I think that can speak on a regional note but that has consensus building process and kind of a checkoff back with states to say, you know, this is -- you know, we're going to carry this part of the burden of transmission. We're going to carry this part of the burden of generation for the southeast. This is what it means to us in terms of rates and charges to consumers. This is what it means environmentally.

Has it been through a review process to make sure it's some type of a near optimal solution? I don't -- I don't think we'll ever find a global optimal but some near optimals would be nice.

MR. CARRIER: Yes, Brendan.

MR. KIRBY: How would you balance the desire to have -- to have customers not be exposed to the volatility with benefits you get from having a price signal that reflects changing conditions in the power system?

COMMISSIONER ATKINS: I don't know the answer to that. I guess in some states -- you know, Pennsylvania is put up as a great example of deregulation and they have price caps. I guess that's how they reduce volatility and still have a deregulated market.

I'm not an economist. I don't have all the answers. I don't know -- I don't know what that means. You've got to have volatility, you've got to have certain price signals, but clearly a lot of utilities try and minimize volatility through hedging.

There's going to have to be some type of metrics there that we can implement to allow some on the benefits of wholesale markets but, at the same time, not beat up on consumers because I think, in the long run -- and we saw what happened in California.

In that case, you know, consumer price caps were in place and the utilities went bankrupt. In our case, I have consumers last year who called me every day that could not pay their bills and hundreds of millions of dollars to our interstate utility has not -- that have not paid. So in that case, volatility turns around being negative to the marketplace, I believe.

But I don't have the answers. This

is -- and I'll be honest with you. This is part of my problem with this huge experiment, and I think it is an experiment.

There's some places perhaps we cannot deregulate, that we cannot do this or we don't need to do it because it's not in the broader public interest. There's some -- some places where prices have been high and there are efficiencies to be gained through deregulation and it's all good and well.

MR. GLOTFELTY: Commissioner, I want to thank you for being here as well. We appreciate your comments in traveling to be here with us.

My question deals with the Tennessee Valley Authority. Since that is a federal government entity, I'm interested in your comments on what role they -- they do play and what role in the future they might play in the reliability and planning and coordination in the southeast if they were to become a part of a whole southeastern RTO.

Is there something that we, as the government, can do to try to encourage them to play the game?

COMMISSIONER ATKINS: Well, I guess -- I saw an article, and I didn't have a chance to really go through it like I wanted to, on powermarketers.com that I guess TVA had announced they were going to make some large investments in upgrading their transmission capacity.

I think, based on all the modeling that I've seen, and I took a seminar earlier in the year and Professor Overbye was there and ran some models, and I think TVA is kind of the hub of the wheel. It's a critical place because so much of the flows actually go through there no matter where they're scheduled to go.

I think we all need to -- all utilities in all states need to look at upgrading their infrastructure, but I think we do that through integrative resource planning. Perhaps we don't do as good a job as we should, but I think the mechanisms are there.

They probably need to be expanded. They need to be made more regional. We need to do it, but we don't need to spend money use -- I can't talk today. I've run out of -- I've run out of gas here. Needlessly.

Let me make an analog. And I'm trying to answer your question, not go around the world here, but I'm going to use a telecom example. We are on the verge, in South Carolina, as are a number of southeastern states, and then there's some other states that have already done it, to allow the RBOCs, the Regional Bell Operating Companies, to enter the long-distance market through Section 271 of the 1996 Federal Telecommunications Act.

And, of course, to enter that, they have to go through a checklist of 14 points, which essentially shows that they allowed and promoted local competition, have cost-based rate structures and forward-looking TELRIC-based rates and they're -- there are thousands of hoops to jump through and it's very complicated.

Perhaps if we all could have been at that point back then as we are today on the electric side, they would have done things differently if they knew where they were going to be today, and I'm talking about the government and perhaps even the CLECs, the competitive providers and the Bell companies. I think we're getting there.

We're going to have a more robust, you know, bundled marketplace out there for Bell companies and competitive providers, the ones that will survive the recession. But if you'll look at the dollars that have been spent to get us there, you could have taken those dollars and probably done the same thing and accomplished it a lot more efficiently.

It was a grand experiment in inefficiency, contradictory orders from FCC, contradictory orders from states, contradictory rulings from judges, a variable maze of legalities and money to be made on the part of lawyers, and my apologies to lawyers because my wife is one.

Let's don't do that with this. I mean, I cannot imagine that all the southeastern states are not going to take FERC to court over the RTO issue because we haven't had our questions answered.

Let's figure out some way to do this, to promote the investments that you want to make that we need, but only those, and do it in an efficient way.

And I know that's what this is all about, but it's just going to take a lot more conversation, but we shouldn't rush -- rush into this. I wholeheartedly agree with a letter that Commissioner McDonald from the Georgia Commission recently sent to President Bush and he asked for us to kind of call a stop to this right now, the whole

FERC mediation process.

And I think given the events of the World Trade Center and where we are in the recession, I think we do need to take a longer look at this. We need to take a deep breath and make sure that we don't make the same inefficient mistakes that we made on the telecom side on the energy side.

The Bell operating companies would always be there to provide telephone service and we had long-distance service even if we had no local competitive providers. But if we -- if we mess with the electric system, we're in trouble.

Let's don't create a framework that's so complicated and so convoluted in terms of market interfaces and deregulation and lack of any type of planning and consistency with what states and regions want to do that a framework is already set for.

Let's don't do that in the sense that destroys and hurts the system and, in the long run, costs us more and actually undoes the benefits that a -- that a market could bring. So that's a roundabout answer, I apologize, but that's about as good as I can do.

MR. CARRIER: Anybody else down at the end of the table?

COMMISSIONER ATKINS: Thank y'all.

MR. CARRIER: Thank you, Commissioner Atkins.

COMMISSIONER ATKINS: I do appreciate it.

MR. CARRIER: Our next speaker is going to be John Pope with the Southern Company.

And I would like to just make a little announcement here. I do intend to break a little bit before noon, maybe a quarter of, so that those registered in the hotel who need to check out can do so.

I do intend to go right through until that time so if you want to make little trips while we're proceeding, you're welcome to do so.

MR. POPE: Good morning. My name is John Pope. I'm the director of the bulk power operations at the Southern Group. In my group, we operate the Southern control area, handle real-time dispatch of Southern generation.

We also schedule transactions into, out of and through the Southern control area. We operate the Southern OASIS node, calculate TTCs and post transmission and approve the sale of transmission. And we also provide security coordinator services to all the transmission owners in the subregion. There are -- we have a contract with other transmission owners. So that's a little background on where I come from.

The focus of this talk will be a little different than what you've heard so far. I'm going to talk about reliability management. And reliability in the terms that I -- that I'll be talking is really grid management, the avoidance of cascading evidence. That's the big ugly that we all try to avoid is cascading outages.

By the way, my slide flipper today is Bill Newman, who's a senior vice-president of transmission. Bill's here to answer questions when we finish this.

The three areas that I'd like to talk about, first of all, just a quick overview of how we manage reliability today, then we'll move into a large area, like a southeastern RTO or an interconnection-wide RTO, and what are some of the issues that that type of area would raise in reliability management, and then I've got some general things on how can we improve reliability no matter what we do.

Okay. As you all know, the

transmission system that exists today was actually planned and constructed to connect local generation to serve local area load. We did build interconnections with neighboring systems, and these interconnections basically serve -- were intended to serve as backup.

There were economic transactions that took place over those interconnections. They were typically very large transactions, 500 megawatts, for example, which was a typical transaction size. Today, rather than having a half dozen large transactions, we have thousands of 50-megawatt transactions, so the volume of transaction activity has really exploded in the last two or three years.

Interconnections, as I mentioned, were developed basically for reliability, not really for the economic exchange of energy. Market forces have changed how the transmission system is used.

There's a mention that the volume of transactions has exploded and transactions distances used to be next-door controlled area. Now it's from the northeast to Florida.

Okay. Reliability management today. Reliability management really begins with -- with the planners doing their planning studies. The planners will aggregate loads from load-serving entities and the generation plan from generators and they will run studies to determine if congestion exists.

Those studies include all known firm transmission. It will also include firm point-to-point transmission, but it does not include all the non-firm transmission that we typically would sell day in and day out.

They run some -- a contingency analysis to determine the worst contingencies and also point to needed upgrades in the system. The planners run studies on their area, but they also run studies with their neighbors.

For example, in the southeast, they run studies called VAST studies that include Virginia, TVA, Southern and so on, so these broad area studies to include all known firm transmission requirements.

In the operating world, we take in maintenance outage requests from generators and transmission providers and we'll run the -- run studies showing how secure the system might be in future time periods with these maintenance requests.

As we get closer and closer to real-time, that's when it really gets interesting, and that's how reliability is really managed, because you have load flow programs with state estimation that will take data from all the substations, generator loadings, line loadings, bring this data into a program, will calculate the missing data, also verify the accuracy of the other data, so you're building a real-time load flow model that models how the system looks out there now.

The way the system looks today, we may have a dozen transmission lines out, maybe 20 generators off line. That exact situation was probably never studied in any planning study. So you need a model that reflects exactly how the system looks today, what the loadings are, and then you run contingencies on that to identify the next worst contingency.

We have to operate the system in such a way that we can always survive that next worse contingency. We also use that same program to calculate total transfer capability to post to OASIS for near-term sale of transmission.

Okay. Another critical factor in managing reliability today is our transaction management system. When transaction volume exploded, as I mentioned earlier, we had to come up with a way to document the transactions that the merchants desired to flow.

So through NERC, we came up with a NERC tagging system, and this tagging system provides the data required to schedule energy and to perform reliability studies on that proposed transaction.

So a merchant would complete this transaction tag and it would include things like the source, the sink, the amount of energy, the start time, the end time, the transmission service that was purchased on each of the providers, the linking of controlled areas and so on, but all the information that is needed to schedule the transaction and to perform a reliability study on that transaction.

The transaction tag also is used in a -- in the NERC line loading relief program to determine if that transaction actually does contribute flow to the constraint. Also, in reliability management, the security coordinator has a number of options available to him to deal with constraints.

He can implement local procedures which might be -- these are usually contractual agreements on redispatch of generation or -- or contractual agreements on allocation of interface rights. He also has the ability to implement NERC line loading relief, which involves transactions from wherever in the interconnection that might contribute to that constraint.

This little map just shows the layout of the security coordinator system, and you can see in our -- in SERC there, you've got the TVA, Southern, Duke and Virginia Power and then the FRCC is down at the bottom there.

Okay. Let's switch -- switch gears a little bit and talk about large area reliability management. How does it differ from smaller area management that I've been talking about? What are some of the things that a large RTO must have if he is to manage reliability?

First of all, he must have local knowledge. Operators have a span of knowledge of the system that they operate. They understand how the system reacts to certain events. They understand when they can push the system above alarm levels and when they can't, and this local knowledge is experience-based and it exists everywhere.

In the northeast, you have operators with local knowledge. In the south, you do, too. Of course, that points out one of the issues we'll discuss in a minute. Bringing all the control into one point, you still have to find a way to maintain local knowledge, but it can be done.

Observability and monitoring, the RTO must be able to monitor critical lines and generators at his central point so the -- so the system that brings all the -- the schedule system, that is, that brings all the data in must be expanded or interfaced to allow central monitoring of alarms.

The RTO must have forecasts. These forecasts may come from load-serving entities that locally forecast their load. He will certainly have to run forecasting programs over the large area of responsibility.

The RTO must have control. The RTO must be able to control breakers and generators either -- either through direct push-button control, using supervisory control or through arrangements with transmission operators that -- to have them operate devices at his order.

RTO must have a governance system that will support the items above, a governance system that will allow hierarchal control, a governance system that will not slow down our response to threats to reliability.

I mentioned the hierarchal monitoring and control. In my mind, this is critical to a large RTO implementation. It's really bothersome to think about one control room with a bunch of operators for the Eastern Interconnection.

In my mind, you will want that to be dispersed in a number of regional or subregional RTO control centers and maybe once -- could have a central RTO control center, but the key to it is to have local area RTO control centers that can run these real-time programs, can look at contingency analysis and can make decisions locally in a -- in a short time period.

Transmission and generation outage planning. This will become a bigger and bigger factor as we have more and more generation trying to schedule outages at the same time.

Of course, transmission outages and generation outages combined -- this is our time of least reliability probably is the time period in which we have transmission lines that are out for maintenance and we have generators out for maintenance and you're in a situation that has never been studied before in a planning study so you have to be very careful in spring and fall in allowing and managing transmission and generation outages.

Cost and redundancy. It appears to me that a large area RTO would be somewhat more costly than a subregional set of RTOs. Simply to fund the central site, I'm not sure in my mind what the payoff is for that, but if -- if it is decided that's what needs to be done, I'm convinced it can be done.

You will have to build in redundancy, that is, if a subregional RTO runs security analysis, then we can have the neighbor -- neighboring RTO also run analysis on his area or you can have the control areas under that RTO run security, but we need to build redundancy into the plan. We need more than one person studying reliability.

In the write-up, the question was asked, is grid reliability a commodity? In the sense that grid reliability is the avoidance of cascading outages and the management of contingency is to avoid that, then I guess it is -- it is a commodity in that everyone receives this reliability as part of their transmission charge.

Okay. This is just a little block diagram to try to picture what I was trying to say about a large RTO. You'd want to have a number of subregions. I don't know if four is the right number, maybe three, maybe five, but some number of RTO subregional offices that would maintain some local knowledge of a certain part of the transmission system.

You could also have a central site at the top there, but there would be much -- there would be much independence in these regional areas to allow for quick decision making. Under -- for example, under Subregion B, you would have multiple controlled areas. And under each control area, you would have -- within each control area, you would have multiple transmission switching centers.

So if the RTO approves a line outage, then the actual implementation of that line outage would be done in the transmission control centers where switching takes place. The RTO would not issue switching orders. That needs to be done by people that are familiar with the switching and safety practices of the field people in that -- in that area.

Okay. What can we do to improve grid reliability? Well, as you heard earlier this morning, generators are popping up everywhere. Every place a transmission line and a pipeline cross that's got a little water, we're building a generator there.

If that's close to the load, that's good, because in managing reliability or in integrative planning, as mentioned earlier, the closer the generation and the load are to each other, the more reliable system you'll have. That's just kind of common sense.

So the first point there, location, location, location, is very important. As things are turning out right now, it appears that generation is not appearing close to load centers, so this has implications for grid reliability and the need for transmission.

Also, dispersed control and communications. A major concern would be a single RTO control center with all the SCADA information coming in, all the readings coming, all the control from this one control center, and you have there potentially a single mode failure where if that control center, something happened, a fire in the control center or even a terrorist attack or whatever, that could impact reliability for a major region like the southeast, another reason why we ought to consider dispersed control into multiple control centers and then have some governance arrangement with a central RTO site.

Okay. So, I guess, can a large RTO such as the southeast be designed to be reliable? Yeah, I think it can. Are there -- are there advantages to doing that? I don't see many, but it can be done.

But in any case, as we move with something this critical to society and to the economy, let's take it slow. Let's understand what we're doing, the implications of these changes to reliability and let's be sure we can operate reliably.

MR. CARRIER: Thank you very much, John.

Now, in asking your questions here, I would like to just point out to the people on the panel that our next speaker is also from Southern Company. He's going to be addressing the issue -- he's going to be addressing the issue of transmission planning and the need for new capacity so we might focus our questions here on the transmission system operation and interconnection.

Since you're responsible for that part, Fernando, we'll start the questioning with you.

MR. ALVARADO: Yes. I have two questions. The -- the first question is that I -- it's been said and, to a large extent, demonstrated in a properly done pricing system the need for TLR as the primary means for addressing some of the security constraints and real-time (unintelligible) constraints either disappears or is greatly diminished.

Do you have any comments regarding that issue?

MR. POPE: Well, I think -- I think your point is true, but I think the need for a line loading relief, a command in control type line loading relief like the NERC process is necessary in case the market does not provide, in case there's not enough ancillary service to re-dispatch or whatever, then you always need a system that can address constraints in a command and control fashion.

But allow the market to address the constraint initially, sure.

MR. ALVARADO: Okay. The second question is related to that. You also were talking about outage planning becoming a bigger factor. And to some extent, do you think that with the proper system in place, again, if you're going to move to a more pricing-based system, that the market itself, the operators of the units that are planning on their own outages and maintenance schedules will now be sensitive to the needs of the system and do involve the analysis required and there will be no need to have a centralized planning of outages, or do you think that that's going to be necessary to have -- to tell people when they can go out for maintenance and things like that?

MR. POPE: Well, I think a centralized analysis and study of integrated outages, generation and transmission, will be necessary, that the reliability people have to study the system as forecasted with generator and transmission outages that are planned.

Now, will generators do that and adjust their outages themselves? You still need to have -- someone needs to do this centralized plan so that the generators can see the impact that they're having.

And then how you will negotiate among generators to move their schedule -- one generator's schedule and leave the other where it is, I'm not sure how that will be handled. The -- the transmission outages is a little easier in that the

RTO will have control over transmission outage scheduling and he can study and allocate outages, you know, to best manage the system.

So -- but in any event, it appears to me that someone needs to study the generation and transmission outages together for each future period to keep us out of trouble reliability-wise.

MR. ALVARADO: A final question, if I may. The -- I -- you made this very, very important comment, I think, on local knowledge, that it is such a key component, and I've actually observed it firsthand, things that we need to know.

There's a certain adaptability that is very hard to convey to the market or to outsiders as to what the system can do under a given set of conditions, if a storm is coming, if a storm is not coming, if you see certain things developing, if you don't.

It's very difficult to create the right things, and yet I think it's going to become necessary to somehow translate that local knowledge into signals that people can understand that are doing the trading, that are doing the -- the inter-regional decisions.

Do you have any suggestions on how

that local knowledge can be exported and extrapolated and used?

MR. POPE: Well, I'm not sure it's not happening today. If -- first of all, local knowledge -- if you had one central site and you divided the grid into subregions and you had operators who always operated certain subregions of the grid, then they could maintain some local knowledge and be at a central site.

Now, a lot of the interface that you have with local people, construction crews, operators, you lose that, but you could maintain some local knowledge even at a central site. Your -- the point of your question again?

MR. ALVARADO: Well, the -- the point of the question was that -- you know, how do you -- if you're looking at people whose concern is essentially trading the markets next to a group of people whose concern is security of the system, we need to somehow have the concerns of the security people communicated in an effective way to the market people so that the right things happen. That's kind of the point of the question.

MR. POPE: Well, it can be -- it can be reflected in how much transmission you make available. For example, if -- if a -- if a storm is coming and you suspect that you'll have line outages due to that, then the TTC could be adjusted to send a natural signal to the market that transmission capability is likely to be affected in the next few hours.

That's -- that's one way to reflect knowledge that transmission operators have into market signals. That's the only one that comes to mind right now.

MR. CARRIER: Okay. Any other questions regarding transmission system operation?

MS. TERRY: I --

MR. OVERBYE: I've got some, Paul.

MR. CARRIER: Okay.

MS. TERRY: I just have a follow-up to this. I guess maybe from a marketer's perspective, simply sort of watching the available transmission passing changes on the OASIS, and it's somewhat of a black box, that is, that there's not really -- it's probably not that easy for them to understand or anticipate what those changes are going to be.

And as a follow-up to Fernando's question, how can -- how can transmission operators provide more information so that it is easier for traders and marketers to anticipate what might be happening to transmission, not just over the next hour but over several days?

MR. POPE: I don't know. It would have to -- as you know, it would have to be available to everyone at the same time.

MS. TERRY: Yes.

MR. POPE: So there's got to be some system, either a posting system or a flushing e-mail system or some way that no merchant can be advantaged -- or all merchants have equal access to the information.

It could be a NERC website that you could keep up all the time that would show information that transmission providers want to have available to the marketplace. There are probably ways we could do that if there's -- if there's real value in it.

MS. TERRY: But you don't see any particular sort of tools or processes under development right now that are moving towards something like that?

MR. POPE: No.

MR. CARRIER: Okay.

MR. OVERBYE: I've got several

questions. One is a follow-up to Tracy's question. Do you see any transmission data that -- or maybe I should say, what transmission data do you see as proprietary that you just absolutely cannot release to all market participants?

MR. POPE: Oh, there's lots of transmission data that would be proprietary; for example, outage schedules and the impact they would have on TTCs. If you know ahead of time of an outage being scheduled, then you can make transmission arrangements to either get there first or alternate arrangements that would give you some advantage, so there -- there are lots of things that -- transmission information that goes into the calculations for available capacity that should be protected.

MR. OVERBYE: But what if -- what if everybody had that information? Is there any inherent reason why you couldn't --

MR. POPE: Okay. That's another approach. If all information was open, everybody knew everything, which frankly sounds good to me, if everybody had equal access to everything, then that problem wouldn't exist and those that could make the best use of that information would win, but that's

not the way that our industry operates today in
transmission.

MR. OVERBYE: Okay. I want to switch gears a little bit. Buyers' new transmission technology so we're looking at ways to increase the capacity of the grid without just building new AC lines.

Given that you walked us through EMS functionality here, and you're certainly an expert in that area, I'd like your opinion on, do you see improved EMS technology, perhaps better algorithms, faster computers? You know, you mentioned there was a problem with -- you know, in real-time, you never deal with situations that were planned.

Do you think there's a lot of extra transmission capacity that we can get through these software improvements?

MR. POPE: Do I think if we had better tools we would find transmission capacity that's not being used? I don't think so.

One of the -- one of the -- there are two points to make on that, I guess. First of all, the real-time tools that are used in load flows with estimation, you can't -- you cannot run a system as large as the southeast in real-time.

There's no tool available to my knowledge that will run a large -- that large a system for state estimation. The data requirements or -- it's a difficult program to get running correctly and keep it up.

It takes a lot of manpower. If you -- if you expanded it, it would be even more complicated to run. One thing that could and does help -- with the technology thing that could and does help with more -- making more transmission capacity available is real-time monitoring of lines, that is, with wind detectors and temperature detectors, so that you can adjust the capability of the line based on the ambient conditions and thereby raise the alarm level and raise the line capability and reflect that in -- as more transmission capability to be posted and sold. And we have some lines with that capability and probably will add more in the future.

MR. OVERBYE: What about on the -- on the hardware? Do you see any new hardware, FACTS devices, superconductors, something like that, that's figuring into your planning that you think should be emphasized in our report?

MR. POPE: Well, the FACTS devices have their applications. They're still very expensive compared to alternatives, but that -- that -- that difference is in some cases getting pretty small now.

One of the things that bothers me about the FACTS devices is when I hear about placing FACTS devices around the interconnection and bringing the control for that to a central site and let's monitor flows and let's open the valves and close the valves, so to speak, and move energy as we like to see it move, then I'm worried -- I'm worried now about this central site single failure.

And if something happened there, how will the system react to that? So that's a concern that must be dealt with if we're going to have a centralized control of many FACTS devices around the system.

MR. ALVARADO: I would like to follow up with a question as to whether you think it would be a good idea for -- again, the government is now trying to offer some services on the things that it might do to facilitate a better -- in this case, we're dealing with operations. This is what you brought to the table here.

And you just brought up a very interesting point and, that is, that doing a real-time estimation of the system is a difficult problem. I personally think it's definitely not unsolvable. I think it's well within current capability if enough resources and things are put into it.

What would be your opinion of encouraging the creation of a real-time nationwide, grid-wide state estimation capability as an objective to the grid put forth?

MR. POPE: I mean, I think that would be a wonderful enhancement to reliability, and there -- there are many ways you could design something like that. You can do subregions and run estimators in subregions.

For example, at the same instant, everybody runs their estimator and we -- and we share soft cases. That might be the easier way to manage that type of analysis rather than trying to build a model for the interconnection and think that's going to solve --

MR. ALVARADO: I'm not proposing to solve the problem right now.

MR. POPE: Okay.

MR. ALVARADO: I'm just thinking. That's the question, if you think it would be a good idea to address it, and we have several approaches of which that's one.

MR. POPE: I think the real-time load flows that reflect how the system is operating at this moment is the key to reliability management.

MR. ALVARADO: Thank you.

MR. CARRIER: Thank you very much, John.

MR. GLOTFELTY: Thank you.

MR. CARRIER: I would like to get through one more speaker before we break for lunch. And the next speaker is Perry Stowe from the Southern Company.

And what I'd like to ask you to do is keep it to about ten minutes and then we'll ask our questions so that we can break for lunch at about a quarter of.

MR. STOWE: Would it be permissible to stand here?

MR. CARRIER: That's fine.

MR. STOWE: Okay. My name is Perry Stowe. I'm director of transmission planning for the Southern Group. And in this role, we have a responsibility for planning the bulk network for Mississippi Power, which is located in the State of

Mississippi, Gulf Power, which is located in the panhandle of Florida, Alabama Power, which is in the State of Alabama, and then Georgia Power and Savannah Power & Electrical, which is located in the State of Georgia.

My comments today are regarding planning. I am a transmission planner by training and spent a lot of years with the Southern Company performing this task.

Kind of the topics that I would like to talk about today or talk just briefly about is how we've done transmission planning in the past, how we did it yesterday, and then we will kind of turn the clock forward and talk about what we see could happen in the future and then talk a little bit about the changing environment for transmission. And then I would like to pose some questions for this group to consider as they perform their study.

Transmission planning yesterday. Traditionally the system was planned to serve load in a defined territory. In other words, you were a vertically-integrated utility, you had load responsibility, you were -- in Southern's case, we had our generation and planning. We'd get together, figure out how we were going to serve the load.

To address the question of how we deal with our neighbors, as John alluded to, John Pope, we have several coordination agreements with our neighbors. We do it with VACAR companies, TVA, Entergy and the Florida companies. So we get together as planners and do studies to see how they're serving their load and also look at the seams issues or the interface issues between those entities and make sure that we can move power in a safe and reliable manner with our neighbors.

And yesterday generators were built to serve specific known loads. In other words, in an integrated system, the generators were built to serve its load.

Wholesale markets were not as -- very well developed and as robust. The planner strived to optimize the transmission system for the native load customer. He tried to make sure that your native load customer was provided a very cost-effective transmission system and that it was very reliable.

And since electricity cannot be stored, the transmission systems were designed and built such that when I turn my light on in my den when I go home at night, a generator somewhere in close proximity picks up and serves that load. This is basically how we planned our system yesterday.

How will we plan our system tomorrow and in the future? We predict that wholesale competition will result in a larger and more fluid market, and we're just going to have to adjust our plans for that.

Generators will increase the complexity of transmission planning. I have some statistics a little bit later that will show you how this complexity is increasing within the southeast.

And I think generators have indicated that they would like to be able to move power great distances and in all possible directions as the market dictates, and this really complicates the planning process. If you have a generator that's located and wants to serve a specific load, you can kind of plan for those conditions and those contingencies.

But when you have a generator that wants to be a market participant, then you're not sure where his sink is or where his load -- where his generating megawatts are going to be consumed, and that creates a lot of complexity for the transmission planner.

It is also proposed that the RTOs will

do the transmission system planning. And here again, I think this is going to be an area where there's going to have to be a lot of discussion. If you move all of the planning authority up to the RTO, I think you're going to still need some planning that is done at the more regional-type areas.

Okay. The transmission system is very stretched now. We're seeing, as John alluded to earlier, a lot more transactions on the system. We have load growth. We have multiple users using the system. John indicated a number of transactions that's taken place within Southern. And all this just puts additional stresses and strains on the transmission system.

You also have cost constraints. Maybe you just don't have deep pockets. Transmission can get very expensive when you start building the higher voltage transmission facilities and so you have cost constraints, multiple users, and then the load growth.

All this is kind of a delicate scale and has to be balanced. We, at Southern, have looked at some of the FACTS devices. You've asked several questions about the FACTS devices. We have studied those.

That is something that we evaluate, new technologies, but so far we have felt like that there are more traditional solutions that are cost-effective, so we have not been able to install FACTS devices.

Okay. Now, I'd like to move into some questions that I think this -- this study should ponder. The questions would be: Has a study been performed that justifies that the nation will have a cheaper and more reliable power supply under the proposed model?

We feel like that the cost to serve load is very distant-sensitive from a transmission perspective. In other words, if the generation is located closer to the load that it's trying to serve, you're going to have to have transmission but you would not have as -- have to have as much transmission as if the generator were located in Maine and trying to serve a load in Miami. It just takes more transmission than that to be accomplished.

We feel like that the transmission investment needs to be balanced with the generator fuel transportation investment. Currently a lot of generation is being developed on the Southern system as gas-fired generation.

Some analysis that we performed indicates that we need to look at very closely, is it cheaper to build gas pipeline to support a certain megawatt capacity or transmission lines that would move that same quantity to capacity? Our analysis says that maybe the pipeline is cheaper than transmission, so we just feel like this question should be addressed also.

Also, if you have a remote power supply, it's probably less reliable than one that's closer. And by this, I do not mean to imply that the generator is not as reliable, but every time you add additional facilities, a mile of transmission, you just add another level of exposure that can impact the reliability of that supply.

And then another question would be: How are we going to recover our new transmission investment expenses for new generators? We're getting a lot of -- we have a lot of questions and concern about if a merchant-type generator is on the system and acquires additional transmission, how do you allocate or recover those costs? It's going to be a question that will have to be addressed and a lot of attention paid.

The next slide, I want to just give you -- the next is just to kind of give you some numbers on activity the state can (unintelligible) within in the southeast. I contacted my planning counterparts at TVA and Entergy and they have supplied this information. It's not apples to apples, but I will try to explain.

The point I'm trying to make is just show you what the planner is dealing with. In TVA, between 2002 and 2006, they have a resource need of about 2800 megawatts. This is load growth basically for TVA. The planners in TVA are looking at potential generators of over 44,000 megawatts so just think about this. You have a need of less than 3,000 and you're looking at 44,000, trying to do transmission plans for all this.

Our friends at Entergy, through '09, they have a need of approximately 2100 megawatts of new supply in their territory. They're evaluating over 65,000 megawatts of generation. From a transmission planning perspective, we could stay up late at night working on how to solve some of these issues when you have this kind of load growth magnitude.

On the Southern control area, this is

not just Southern Company, this has the GTC, MEAG and Dalton, which are ITS partners that our first speaker mentioned, there's a little over 15,000 megawatts of resource need, and this will include some retirement.

Southern has some units that will be retired so this is not all load growth, but it's resource needs, 15,000 megawatts, and we currently have, in our OASIS queues, over 98,000 megawatts of generation. So this is the type of problem that's causing the planners some issues.

So the question I have associated with this is, do we build a transmission system to handle this magnitude of generation? You know, I personally don't think it's all going to be built. Some of it will be built. The question is, how much will be built? Which ones will be constructed?

A lot of our generators are requesting interconnection requests but not a transmission service request. What does this mean? Well, they're saying they would like to build and interconnect into your system, but you don't know which way the power is going, so how do you plan transmissions? Do you go to the north side, east, west, or some combination thereof?

So this is one of the concerns that's facing the planner every day. And as the numbers indicate, the generation exceeds the load growth in the area. So if this generation is built, it's going to have to go off the system so, again, which direction do you want to move the power?

And let's assume that a portion of this or -- a major portion of this generation is built. What impacts are you faced with? Well, we feel like, as I said earlier, our transmission system is already stretched. It's being utilized heavier than it ever has been in the past.

We feel like you're going to have to build additional facilities and just determine which facilities need to be constructed. And this is going to bring up several issues, one being right-of-way. It's getting harder to find right-of-way for major transmission lines. That seems to be on the critical path for getting new facilities constructed is obtaining, clearing and getting the right-of-way perfected.

We already have -- we're running into limited resources to design and construct the new facilities, so I think this is going to be an issue that -- you know, you know there's going to have to be additional construction entities out there that are willing to jump in and build these facilities as needed.

The next question deals with the Southern Company. It covers about 92,000 square miles in the four southeastern states I mentioned earlier, has 4 million plus customers, as of 2001 peak territorial demand, a little over 38,000, has rates in the lower quartile. When you look at the rates consideration, we have only called two TLRs in the past three years.

Now, for those of you that don't understand TLR, this is a transmission line loading relief procedure where there's congestion that the system security coordinator could not figure out how to get around so we had to call for some curtailment of some transactions.

And I guess the point I would like to make on this is that for a system this size to only have two in the last three years, you know, John Pope and others in the southeast must be doing something correctly.

My question is, if a region this size has a low delivered energy cost, has a high degree of reliability, only two TLRs, do we need to add additional costs, potential reliability issues and other associated complexities to the system that we have -- currently have in operation?

In summary, I think transmission is facing and has many challenges. One is financing the future capital needs. The plans that we currently have on the books within Southern is very capital intense.

There's a lot of concern with how we're going to finance this or how we're going to develop innovative ways to figure out how to finance future capital improvements. How do we respond to transmission customer needs?

As the previous slide showed us, there's tremendous amounts of megawatts that are out there and you put them in a queue and you start stacking all these requests up, you get some strange answers.

The last guy in the queue that we're currently studying is told an answer as if everyone ahead of him is in service, so you get some very strange answers. You may -- because that guy decides to move somewhere else and all the others go away, so we've got issues like that that are -- we're pursuing because we're going to have to figure other ways to do it.

How do you develop a plan with all the multiple possible scenarios of new generation? We're struggling with that. And, of course, then you have the issue of the uncertainty of industry restructuring.

These are my comments and I appreciate the opportunity to address this group.

MR. CARRIER: Thank you very much, Perry. I'd like to start the questioning, I guess, with the bearded gentlemen on our panel, the two responsible for this section, Brendan and Eric.

MR. HIRST: I have a question. Perry, in -- in John's talk, he raised some issues that I think really go more to your areas of responsibility.

He said that basically generation is kind of popping up all over and it doesn't seem to be located strategically relative to the load centers. My question is, in what part of the country is that true, because I think in both New York and PJM, the generation is being located closer to the load centers?

For example, in PJM, I think the amount of congestion from west to east has gone down quite a bit in the last few years. And in New York, there have been lots of proposals for generation in or near New York and Long Island.

It was actually leading to some concern that generation can get bottled up. It's hard to believe, isn't it, that New York City may become a net electricity exporting region?

So part of my question is, where do you see this particular problem happening; and the second part of it is, to what extent would congestion pricing help solve that particular problem of poor locations for generation?

MR. STOWE: Okay. On the first question, we're seeing a lot of our generators, as I said earlier, being gas-fired because there's a lot of gas along the Gulf Coast. Entergy sees that, Southern sees that. So there's a lot of generation that is being located close to the fuel sources. Fuel is a little bit cheaper the further you go out.

So when a generator looks at his fuel costs, he may decide to locate closer to the wellhead or -- to save some fuel costs. A specific example is that we have what's posted on our OASIS what we call our southwest quadrant, which is basically the Southern part of Mississippi Power, part of Alabama and the Gulf, where a lot of generation is located, and we have to manage our export from that quadrant because the generation in that quadrant exceeds the load.

And we've run into a stability issue. And we're seeing this more and more in other areas within Southern where generation that wants to locate exceeds the load and we're bumping into stability limits as well as government-type limits also.

And your second question was congestion pricing. You know, I think congestion -- I'm not a policy person so I'm speaking from a transmission planning perspective here. I think congestion pricing could work. I think we just need to take our time to figure out how to make it work so that we do send correct signals to the generators and hopefully they will locate in appropriate areas.

Some other drivers of where a generator can locate are non-attainment areas. Unfortunately we have some of those in the Southern system so that dictates that generators cannot always locate right up next to the load, you're non-attainment from an environmental standpoint.

MR. KIRBY: This question, I suppose, is for both you and John. Many of the reliability rules involve a trade-off of costs against reliability. Sorry. I'm wondering if you see -- and since it's the -- it's off -- the customer that's bearing the consequence of the change in the probability, say, of an outage, do you see a need for or a mechanism whereby you can get more input from the -- perhaps the load side as opposed to, you know, traditional where it was primarily from the generation and transmission side and how do reliability rules make that trade-off?

And a couple of examples might be NERC recently moved from ten minutes to 15 minutes for the response to -- contingency response which obviously has some impact on the probability of a second vent during that time period. Another could be, as we discussed a little bit earlier, the idea that a system operator might elect to make less use of transmission when a thunderstorm was approaching.

I'm wondering how those kinds of decisions -- which are probably excellent decisions, but to my knowledge those seldom or never involve the customer having the ability to reflect preference for the level of reliability they'd like to see on the system.

MR. STOWE: John, do you have any

comments you want to make?

MR. POPE: Well, the expense of getting --

MR. CARRIER: There's a microphone right beside you there.

MR. POPE: Then I can do the question justice. The expense of getting inputs from all the different customers, no one's really worked out how that might work. And you're right, that's the missing ingredient here is to get demand response from -- from customers to indicate what they're willing to pay for the service.

Yeah. And Bill just reminded me. At Southern, for example, we have a significant amount of the load on real-time pricing, both -- more than anyone else in the country, over 4,000 megawatts on real-time pricing either a day ahead or an hour ahead, so we do get a load response from those customers, but that's not really what you're getting at, I think, that is, how much reliability are customers willing to pay for?

And I don't know the answer to that, but it's our experience that when we have outages, customers want to be on, they want to be on now, and I'm not sure that the -- some marginal cost in energy during that time is going to be significant to any of us.

MR. KIRBY: Well, to extend it a little bit, the example of an operator's response to a thunderstorm, you can see how that would work in a vertically integrated environment where the system operator essentially owned the generation and could make that decision and could therefore lean in the direction of higher reliability for the customer.

It seems that in the market environment you might find the remote generator pushing back, saying, I want to see the exact rules that allow you to curtail me during this thunderstorm. And I can see how -- how that generator would have a -- a means to voice that concern, bring up the concern.

I'm wondering, do you see a way that could counter the influence where the customers might be able to say, We want to see that activity continued?

MR. POPE: You know, the -- when you asked earlier, how can we get transmission information even to merchants so that they can react, and this problem would be -- seems to be much larger than that. How do you get it to every user so that they can react?

I don't -- it's not obvious to me that there is a mechanism that you can -- that you can do that unless, you know, everyone's computer in house is programmed to -- when they get certain messages, they turn off. I'm not sure --

MR. KIRBY: Well, I was really asking more about -- though that's an excellent issue, I was really asking more about in the rural development as opposed to the real-time response, you know, what -- how it is that -- NERC's decision, for instance, to move from a ten-minute to a 15-minute response was a slow, deliberate process, but I'm not aware that it got much load input into that decision process.

MR. POPE: I don't know the answer to that question.

MR. STOWE: To address the plant prospective, I know we're looking at -- Southern Corporation and EPRI, excuse me, has been developing a more probabilistic approach to planning. In other words, we're factoring in the frequency and duration of the outages and that applies -- you're, in fact, able to evaluate how much additional risk you're willing to take.

In other words, historically you may

have looked at a generator line out; and if you had a problem, you built a facility. Well, you go back now and put some probabilities on that to see, you know, what is the probability, how much load could be impacted, and some of the planning decisions are changed there so that planning side is now how reliability is being (inaudible) and the frequency in relation to that.

MR. ALVARADO: Okay. I'm going to change gears a little bit. You have mentioned this peculiar fact that when you have a bunch of plans you put them in order and the order matters that you planted in first and, of course, by the time you're eighth in the line or tenth in the line, things look very, very funny.

There may be a different way of approaching that whole thing, you know, so that everybody sees the input of everybody else regardless of order. This issue of having things dependent on the ordering in which you get them in is the same -- is somewhat similar to this TLR reservations and things like that where, you know, nobody -- people don't see the value of other people, the impact of later decisions, and I think if I could -- I don't know how to phrase the question, but have you considered a system in which you kind of pool all the plans as they develop, as more people put plans in, even the earlier plans get affected so you see the simultaneous effect of all these things and people can withdraw or add or whatever?

MR. STOWE: Yes. Well, from the input that we've received from the requestors, queue day is very equivalent to them. They like to be the first one in the queue. They feel like they have a slot, they have a slice of what the system conditions are.

I think we are going to have to change that for the very reasons you talked about. You know, maybe you should look at an area and determine what the fix is with a group of generators coming in and figure out some kind of cost sharing mechanism. Maybe the first that got it get the free ride and the last guy that pays for all of it. Maybe they all have some kind of cost-sharing mechanism so that everyone could have service.

MR. ALVARADO: Or they all see the impact of the combined decision. Essentially the minute you get free riders, you're putting a bias into what happens and then people will drop out or be added, but I think that you really -- I mean, it's not a question, more a comment, you may want to reconsider that.

MR. STOWE: Okay.

MR. GLOTFELTY: Thank you. I have a similar question about the queue and was just going to suggest that if you have thoughts on the way we could reform -- propose reforming the whole queue system.

I believe it's inefficient for transmission owners and planners to have to study probably 50 or 60 percent of these projects we're trying to get rid of.

MR. STOWE: Right.

MR. GLOTFELTY: And if you all have comments or thoughts on how we're going to reform that point forward so that it's efficient for you and it's efficient for the marketer and it's efficient for the generators, I would love for you to submit those.

MR. STOWE: Okay. We will do that.

MR. GLOTFELTY: Secondly, and you're more than welcome to just submit these as opposed to talk to them now, we asked one of our power marketing administrations in the west to -- to try and determine, kind of a back of the envelope calculation, how many miles of unutilized right-of-way they have today and how many miles of existing tower space, where they were probably built for double-circuit towers and only single-circuit will sag, is there a way that we can determine what capacity that we have out there or what right-of-way we have out there that could be utilized or should be utilized?

This -- we kind of got to this point because we're, of course, going through the process of determining if a federal eminent domain authority is necessary for transmission siting.

And through our work with our power marketing administrations, we're trying to find corridors in the west that have already been created, right-of-way that's already been acquired, to make it easier for them so we don't have to use (inaudible).

Is there a way that we can get that information or do you think it's useful?

MR. STOWE: Well, I think on the Southern situation, I'm not familiar with a lot of unused right-of-way, quote, unquote, but that's not to say you could not change your tower design, get a more compact design or something like that, or go back and retrofit, which we do. We retrofit.

We're currently taking a line down now

between Alabama Power and Gulf Power using existing right-of-way -- a 115 right-of-way to come back to 230. That's not to say don't do it, but as far as saying there's a lot of excess rights-of-way, I don't think that we have that in the Southern system.

Another thing we're beginning to do, some of our companies are beginning to see that we're going to have to build some kind of transmission. It's going to be harder and harder to get right-of-way so we're going out and purchasing right-of-way for a corridor before the actual facility has been announced and even planned to try to get a jump on the right-of-way issue.

MR. CARRIER: Thank you very much, Perry.

We'll take a break for lunch right now. And there will be a -- there are a couple of little things I want to mention as we break. We will be convening at one o'clock. We have five speakers remaining that we want to hear from, and let me just mention their names, Arthur Fusco, Jerry Howard, Christine Mest, Belinda Morrow and Ross Malme.

If you don't hear your name there and you do want to speak, please re-sign up at the desk just outside the door and we'll take additional speakers. Also, I want to mention that we will have somebody in the room or just outside the room so if you've got bags or something that you want to leave behind, feel comfortable to do that. Thank you.

(Lunch recess from 11:53 a.m. to 1:05 p.m.)

MR. CARRIER: Welcome back. We had some consolidation over lunch so we're down to three speakers remaining that we're going to hear from. However, we do want to give you the opportunity -- anybody else at the end, I will open it up if they have additional comments or would like to remark on something that was said earlier, we'll give you that opportunity as well.

But if you're trying to keep track on plane schedules and such you're thinking about, I suspect that we'll probably be done by 3:00 o'clock without any problem.

Let me mention the three speakers that we do have. We have Jerry Howard, Central Electric Power Cooperative, Ross Malme from RETX and Steven Herling from PJM Interconnection. And we'll start with Jerry. Thank you.

MR. HOWARD: Thank you. Y'all messed us up by -- you didn't go by the schedule so we were -- we were going to talk about the business model, if we have an RTO, what business model we think would work best. That was going to be first on the agenda and we ended up being in the afternoon, so we'll have to deal with that, I guess. But, anyway, nobody's talked about it yet to any great length so I feel like it needs to be talked about, so let's talk about it. Okay?

Central Electric Power Cooperative, of which I -- my title is vice-president for engineering operation, and this is a G&T co-op in South Carolina. And you've already heard from our hero and our commissioner, Dr. Buddy Atkins, and he stole a lot of my thunder, but we represent consumers, just as he does.

And consumers, we feel like their best interest is served if we keep their rates as low as possible and their reliability as high as possible, and we think we're doing a pretty good job of that in the southeast. And if we do anything to raise their costs, then they're going to come and see us, as Dr. Atkins pointed out.

And having served for some time as a -- as a member of local government, as a county councilman, when we had an increase in taxes, people came to see us, and sometimes they had subtle reminders like hangmen's nooses and things like this, so, you know, they -- if their costs go up, we're going to hear about it, and we're very sensitive to that.

And we don't -- we serve them. We work for them. We're in the co-op business. We work for consumers. The Public Service Commission does also. And our -- our chief goal is to keep their costs low and their reliability high. And in the southeast, we've done a pretty good job of this.

We welcome an opportunity to present our views on what we have come to see as the key issue regarding restructuring of the transmission component of the electric industry in the southeast. We're talking about a national grid here, but as a component, the southeast RTO concept is what we've been trying to deal with.

And whether the national grid is necessary or not, nobody's really talked about that, but if it is, it's desirable, but we're not sure -- I'm not sure that it should be as high a priority as we seem to be making it right now, considering everything else that's going on.

And if it is a higher priority, then

we feel that the federal government should be involved in it in a more direct role, and this has been borne out by -- what the NRECA has proposed to Congress and, that is, that we should be using federal programs if we want to develop a national grid in order to build facilities.

As I said, we're a generation and transmission co-op and our member rural electric cooperatives provide electricity throughout South Carolina. Together Central and Santee Cooper, which is South Carolina's state-owned public power system, have built the largest generation and transmission system in the state.

Both Central and Santee Cooper serve South Carolina consumers on a not-for-profit basis. Neither Central nor Santee Cooper is a public utility within the meaning of the Federal Power Act, Central because it is a borrower from the Rural Utility Service, RUS, and Santee Cooper because it is a municipality within the meaning of the act.

It's not the policy of the State of South Carolina to deregulate the provision of electricity at retail in the state, notwithstanding some rather vigorous advocacy by interests favoring deregulation.

Consequently, radical restructuring of the transmission component of the system is not an urgent priority in South Carolina as it is in states that have elected to deregulate. This seems to be the situation in most of the southeast.

It's probably no coincidence that the price of electricity is lower in South Carolina, as it is in the southeast generally, than in those parts of the country which have elected to deregulate.

All these circumstances have shaped Central's perspective on the NTGS study issue on which it wishes to share its views most today: The appropriate form of an organization to develop further the regional transfer infrastructure in the southeast.

If control of transmission in the southeast is to be regionalized, Central's view is that the vehicle should be an organization which does not itself own the underlying transmission assets.

In the terms employed in the NTGS discussion on the subject in its -- on its website, this organization should be an ISO rather than an ITC. And we have two principal reasons for our very strong preference in this regard.

First, the ISO model is likelier to

result in regionalization of the entire grid. The ISO model assures that entities which are not permitted by state law to own equity interests in for-profit enterprises would be able to subject their transmission facilities to control of an RTO on precisely the same basis as firms that do not labor under any such restriction.

In contrast, the ITC model, as represented by the GridSouth proposal, for instance, enables the present private owners of the transmission facilities to actually own the RTO, whereas entities prohibited from ownership in such an enterprise can only participate on a less-than-ownership basis.

Such second-class status is particularly repugnant to entities that serve on a not-for-profit basis. It will amount in effect to lending facilities built by consumers in the expectation of not having to pay a return on the investment in them, to the extraction of profit from those -- from these same customers on such use.

In the southeast, entities qualifying at municipalities, and therefore not subject to the full weight of FERC jurisdiction under the Federal Power Act, own very substantial portions of the grid. Without such entities' voluntary cooperation, the resulting RTO in the southeast is likely to resemble Swiss cheese in that there will be many holes in it.

At the same time, the ISO model permits accommodation of ITCs formed by those who may wish to form them. An ISO would have no motive or legal basis for discrimination against the ITCs as compared with other owners of transmission facilities subjected to the ISO's control.

The reverse is decidedly not the case. Since the premise of the ITC model is the acquisition of ownership as well as control of all transmission assets in the grid, there's no apparent role for an ISO within an ITC.

Second, the ISO form of organization would do less violence to existing retail regulatory structures than would an ITC, and without diminishing in any way the prospect for emergence of competitive wholesale generation markets.

This is a particularly weighty consideration in the southeast, most of which has evinced the purpose to retain the franchised monopoly remodel for the provision of retail service, at least for the foreseeable future.

Advocates of the ITC approach rest their case largely upon the contention that such entities could tap markets for capital to invest in transmission more effectively than can existing transmission providers.

Putting aside the plausibility of the ultimate conclusion, this argument rests on the attractiveness of an ITC's balance sheet, i.e. on ownership of the grid. Put another way, the argument is premised upon divestiture of existing facilities by the utilities now serving at retail in the southeast.

There is little reason to believe that divestiture of transmission would be favored by the southeastern states so long as they hew to the existing model for the retail business. Again, a business model premised on changes likely to be resisted by state authorities is not likely to encompass the entire region.

The lawyers wrote that so I had to read it that way. It didn't make a hell of a lot of sense to me. We have been working diligently, along with Santee Cooper and with Southern Company and some other wonderful entities of a municipal and co-op nature.

We tried to put together a RTO business model for the southeast, or for our footprint anyway, that would -- that would provide for an independent third-party operator and, as such, all the entities would keep their transmission ownership and the operation would be truly independent and therefore separate the ownership of generation from the operation of transmission, and we think that this independence will be sufficient to make things happen in the way the national trend seems to be trying to push things.

If we've got to have an RTO, we want to -- we want to make sure it has the least possible impact on the cost to our consumers, and we feel like this model would be the best way to do it. Also, it would include, as I mentioned, all the municipals, and co-ops, it could possibly include them, and possibly TVA.

And if you're going to solve the problems of a large RTO, it needs to be inclusive, you know, the parallel flow problems and the -- all the problems of -- between the seams type -- seams issues would be best served by inclusion. So if we have a non-ownership entity at the top, it would -- the possibility of inclusion would be more likely and therefore a better model for the southeast.

We appreciate the opportunity to make that point and hope that you'll consider us when you go on in your endeavor.

MR. CARRIER: Thank you very much. Hold on a minute. We might have some questions for you.

MR. HOWARD: I thought I did so well there wouldn't be any questions.

MR. CARRIER: Fernando, this is your area of the report. Why don't you go first?

MR. ALVARADO: Well, it's -- Shmuel is the director of all this, but yes, the -- I guess the main argument you're raising is the operation versus the ownership pattern, the importance to separate that.

In terms of the existing models at present, you know, for system (unintelligible), but how do you view -- if you have to adopt a particular model, what would you propose specifically in terms of a business structure if you have the -- to make a recommendation?

MR. HOWARD: You mean for an RTO in the southeast or --

MR. ALVARADO: Yeah. Within the

framework of having to create a RTO in the southeast, you've already kind of told us how you would structure it, but tell me your preference. What would you like to see?

MR. HOWARD: If -- what would I like to see? I would like to keep things the way they are, but if we have to have an RTO -- if we have to have an RTO, we need to minimize the effect on our customers who are members in our own, and we feel that a third-party operator on the ISO model would best serve those concerned and also allow for inclusion of public power not-for-profit organizations and therefore have a full representation of all the transmission ownership in the area.

And that -- you know, we've been through this -- we've been working on this for a long time, had a lot of words back and forth, we had a lot of words with FERC in the mediation process. And, you know, I can't -- I can't begin to tell you all the -- all the things that we have concerns about.

But for many, many reasons, the ownership of transmission at the RTO level is of great concern to us for many reasons that I said. And we don't see how the divestiture of transmission to an RTO by all the FERC jurisdictional entities is going to end up saving money for customers.

This -- they operate as transmission for profit at a higher rate of return than what they're able to earn now and there's not enough efficiencies possible to offset everything.

We have in the southeast very competitive rates based to the national average. We have a cost structure that our members understand. If they start experiencing price spikes and unusual costs, we'll have some real problems and we're concerned about it. We want to preserve what they have, which is low cost and good reliability. I didn't answer your question, did I?

MR. ALVARADO: Well, I think you've added additional points to our list here. Let me ask another question that concerns the -- the Swiss cheese analogy because I'm familiar a little bit with the California situation where they have an analogous sort of situation, where they have pockets of -- within their own system that's not widely known or advertised, but they're in kind of -- municipals and things that own part of the transmission.

And it's one of the biggest headaches they have, the fact that they have to integrate these into a completely different model, which is what they're using. This is apart from the other problems California has had that we've had before, but having disparate and incompatible business model is in itself a problem.

Would you see -- you've just suggested that when every model evolves, it needs to incorporate, have room for these, if you will, not-for-profit organizations as part of the model, but, again, the issue has been raised before that having a diversity of models within one grid, that is, one hole, can in itself create a problem.

MR. HOWARD: Well, the key to an RTO is what the -- what's on top. If a nonowner is on top, then we can deal with it. If an owner -- if the organization itself owns transmission, we have a lot of problems.

And if we're going to have a real RTO, it needs to include all the transmission. In the State of Georgia, you've already heard that Georgia transmission, MEAG and the City of Dalton own significant parts of the transmission system, which is intermingled with the Georgia Power System.

In South Carolina, Santee Cooper owns about 40 percent of the total transmission, Santee

Cooper and Central together, of the state. These -- and TVA, of course, everybody knows how much transmission they have. A big sizable portion of the transmission in the southeast is -- belongs to TVA.

So if we're going to include all these entities, if we're going to have a real RTO that will function the way people want it to function, we've got to include everybody. You can't dis-include somebody who has segments of power lines intermingled with somebody else.

And if you have a structure they can't participate in, then it's just not going to work out. It's -- you know, there are a lot of complexities to it, but it boils down to about that simple.

MR. ALVARADO: Okay. So if I understand correctly, you're not advocating separate operation of the transmission facilities on these nonprofit organizations, you're simply advocating that there should be allowance within the, if you will, business structure models for having portions of the system that operate under a different financial model but not necessarily electrically?

MR. HOWARD: Yes, no and some of the above. The actual operation -- you know, we had a long discussion this morning about centralized operation versus decentralized control areas.

We think initially the control areas should stay about like they are except for the operation of the commercial portion of the transmission system. And functionally that would be -- that would work just fine.

If you start centralizing everything, then you get -- get into problems, as outlined this morning, of reliability caused by loss of communications, various kinds of classes. You need to have some decentralized control. And what we have now is -- for reliability purposes, is working very well. We've got marketing, we've got reliability, and how much do we give up one in order to improve the other one?

MR. CARRIER: Any other questions?

Thank you very much, Mr. Howard. Our next speaker is Ross Malme from RETX, which they gave -- your organization was referenced this morning.

MR. MALME: Thank you very much. My name is Ross Malme. I'm president and CEO of RETX and I'd like to, first of all, welcome this study team to Atlanta, which is our hometown.

RETX is in the business of providing technology and services over the internet to make markets work, electrical markets work, and to assist energy companies in being successful in those markets.

I'm going to talk today a little bit about demand response and some of the solutions that we -- we have. And we're in the market today to help address these specific transmission congestion issues that this team is working on today.

Just a couple of comments about the company, the team comes -- comes from a diverse background of energy companies and technology companies, Accenture, Enron, Southern Company, Andersen and so forth.

As I said, we're headquartered here in Atlanta, Georgia, privately held. We're basically providing market-based technology solutions to supply energy shortage problems. The team's got about a hundred years of combined energy experience in the energy industry.

We are operating what I believe is -- what we call the first regional negawatt hub in North America, and it's actually on behalf of the ISO in New England, where we're actually serving demand response on a complete network to six states in New England.

Some of those states are regulated, some of those states are unregulated essentially, which allows any customer in that -- in any one of those states to sell capacity back to the ISO either when they've got reliability issues or when the prices are high.

So essentially we're turning customers into virtual power plants. And we're now pioneering this application through the use of locational (unintelligible) pricing to be able -- to be able to take that down not only across all of NEPOOL but down to specific load pockets, an issue which you may have seen in some of the transmission studies that the ISO has -- has put out.

A couple of -- a couple of statistics -- and some of the quotes I'm going to use here are from some of the members of the team here. $56 billion required for new transmission over the next ten years to serve our needs as an industry, 125 billion in new generation investment, astounding numbers, you know, in terms of what's going to be required in this industry to support it.

One of the things that we have also

learned from EEI is that the demand response can have an enormous impact on market prices and -- to mitigate -- to mitigate market power, and we really believe strongly that demand response needs to be concluded as maybe the third leg of the stool with generation and transmission as -- as you're making your plans going forward as a -- as a team.

If you take a look at the Energy Information Administration, it's estimating 1300 new power plants will be needed by 2020, and this is an enormous number of new plants and new generation. And all the while, transmission capacity as a function of the demand continues to be declining over the last ten years and forecasted for the next ten years.

What I'd like to talk about real briefly is the specific program that's being delivered in New England. In this particular case, our goal is to get about 500 megawatts of load response into that market. It's about -- a market of about 20 -- I guess this summer it turned about 24,000 megawatts, right?

MR. CARRIER: 22.

MR. MALME: It was 22. And if we can get -- basically what we're doing is going to replace a certain portion of -- or 500 megawatts of their non-spinning reserves with -- or the spinning reserves with load response, and they're, in doing this, saving about $30 million, estimated, in operating reserve payments.

An additional benefit of this is an enormous environmental impact of being able to save a tremendous amount of greenhouse gases in this market as well. We've estimated this summer, there's about $80 million of expenses incurred -- incurred in New England for transmission congestion.

And the ISO, in their last report that they just issued, is now estimating somewhere between 125 to 600 million dollars per year of additional cost due to transmission congestion, which we think can substantially be mitigated by utilizing this resource.

Taking a look real briefly at some of the experience this summer, the demand response program in New England was called on, I believe, a total of six or seven times this -- this year.

If you take a look at -- as prices -- the average prices on the right increased, you can see that the load increased. Actually the load did respond to those prices.

And we really believe strongly, as those economic incentives are even improved further, that we're going to be able to see a tremendous amount of uptick and demand response available.

The network that's running in New England now basically looks like this, where at the top of the slide, the negawatt market is essentially the ISO, who was on the buy side of the transaction, so they're the buyer of the capacity resource.

There's two products that are being served today in this program. One is the mandatory program where essentially the customer is selling the call option up to the ISO and the customer is receiving -- receiving a capacity payment every month. And the ISO, from a reliability standpoint, has the ability to call on that option when they need it. Customers are also paid energy when they do get called.

The second program that's offered by the ISO is a voluntary program where the customer has control of the resource. And when, in this market, customer -- prices are forecast to exceed a hundred dollars a megawatt hour, the ISO declares that the negawatt store is open and customers can voluntarily sell capacity back in -- back into the market.

So what we've essentially created here is a place where individual customers can come in and sell that resource back into the market and be a resource to that ISO. And we think that this is a very repeatable model that can be implemented across an RTO, you know, depending on what product wants -- the RTO wants to provide.

So what we have here essentially is a seamless network over the internet where we can push prices down to every LSE and every customer in New England that subscribes to this network. We have a notification system over the internet that lets these folks know when -- when the opportunity exists.

And essentially what customers are doing is in effect setting a limit order. They're not watching prices every day. They have a limit order saying, I'm going to play at $200, $300 or $400 a megawatt.

And the ISO not only can call for the resource on a NEPOOL or ISO New England-wide basis, but they now will be able to -- in the next year, be able to look at this on a load zone base. So if they've got an issue -- a transmission issue in Boston, they can just call for that capacity resource in Boston or southwest Connecticut where most of the congestion in New England occurs.

And you'll find that from a deployment standpoint as it compared to a transmission -- new transmission or new generation, this is a far, far less expensive way to get new capacity into a market, and we can do it in a matter of months, not years, and you don't have the -- you know, the nimbi effect, you're not in my back yard.

So we really believe this is a critical -- is a critical part of the program. It's not meant to be a replacement of new generation or new transmission. You know, a demand response is probably good for, you know, 2, 3, 400 dollars a year. It's not 80 -- an 87.60 kind of resource, but it's certainly a very important resource in the plan.

Our specific recommendations. First of all, we do support the FERC Order 2000 for the super-regional RTOs. We believe that each of these RTOs need to implement a load response program that targets up to about five percent of their maximum demand in that specific RTO.

And if we can get the locational pricing down to those specific load pockets, we can use demand response on a specific targeted basis to alleviate specific transmission congestion issues. We think that the industry, federal government, RTOs need invest in a -- load response resources, and that means get more of this technology out there.

It's a relatively inexpensive way to get a resource on line. And, again, we can do it pretty quickly and we'll be working with the ISO in this -- over the next couple of months of getting this resource on board from a congestion management standpoint. We're working pretty aggressively right now with the northeast RTO and other RTOs around the country as well.

And I'll be happy to address any questions.

MR. CARRIER: Thank you. I'll start on this side.

MR. ETO: This is Joe. I'm interested in knowing if you could be more specific about specific federal actions that can be taken to stimulate the growth of the type of programs that you're advocating.

MR. MALME: The -- there's two or three keys to this thing. Number one is making sure that there is a liquidity point for customers to sell into. Now, in this case where the ISO is the pricing source, it doesn't have to be.

The wholesale market could actually come in here and practically create a market for this resource and the ISO or the RTO could actually be a customer of that capacity. They wouldn't have to be designing programs themselves. Let the market come in and give us -- and design those programs. All we need is let's -- show us the price and we can get the customers to respond.

The second thing, I think, is making -- making it easy for customers to participate in this program, and that's -- we're working with the competitive suppliers as well as the distribution utilities in offering the product to individual -- individual customers, and that means -- giving choice to customers for those products.

For example, in New England, it wouldn't matter if you were one of the regulated states or unregulated, I believe, you can -- a customer can elect one of several different suppliers for this negawatt resource, so it's depending upon which supplier they want to use.

MR. KIRBY: To what extent is the further implementation of technology slowed by differences in regional definitions of -- of the reliability services, spinning reserve services and the lack of metrics for those services?

MR. MALME: Well, I think -- I think that's a real issue. There's a lot of seams. I mean, there's the PJM program. Just in the northeast, the PJM program is different than the New York program is different than the New England program.

The one thing that I -- that I do -- we do feel very strongly in is the use of near-real-time information in terms of metering information, getting that into the ISO so they can respond to that. We're actually operating this program right now. We're essentially the hub operator on behalf of ISO in New England. We're also operating this service in New York with that ISO and operating it in California as well for -- on behalf of Enron.

MR. ALVARADO: Okay. I have -- I have three questions. The first one is -- you were giving us some numbers, five percent. Why should anybody mandate a given level of penetration? Why shouldn't we just enable this thing and let things happen?

MR. MALME: I think that's a very good point, and I think we're -- where the five percent comes from, I think, is -- from my standpoint, is really a guideline of there's certainly that amount of demand response out there to get.

And if you take a look at the economics of this, you'll find that the economics of demand response to get this capacity is much less expensive than transmission or generation. If we can get more, great, but five percent, I think, is a very good goal.

MR. ALVARADO: It may be, but, as I said, I would let -- once you set up your system, the market will provide --

MR. MALME: Yes.

MR. ALVARADO: -- whatever it's going to provide.

Two other questions. I think you already answered one. What is the penetration? You mentioned at least five percent.

My last question is related to (unintelligible) from a known point. How do you meter and monitor performance on what you're calling a negawatt in the sense that many funny things can happen when you provide a negawatt? I could very easily curtail my -- I contracted ten megawatts and ten minutes later I am up again or I agreed to the ten megawatts and I curtail it on my Plan A and I immediately move it across to Plan B next door and, of course, I've defeated the entire purpose of what we're trying to achieve here.

So how do you -- how do you, you know, assure compliance of what a negawatt really means?

MR. MALME: That's generally a subject of great controversy. And in each -- in each of the markets that we're operating in today, there's a slightly different way to calculate what you're referring to as the baseline and there's differential algorithms that we use for that, whether it's the last ten non-holiday, non-curtailment days or the last 11. There's various algorithms we have for that.

To date, I think at least the programs we're in, we haven't seen a lot of market manipulation, so to speak, but I think the -- the design of that -- of that algorithm and how that works, the business rules of that market, and then finally also being able to measure the response -- I mean to meter the response close to real-time.

And one of the things you don't want to have happen, for example, is for the customer to commit to you five megawatts and he only gives you three and he doesn't know it for 60 days, so -- and he's got socked with some kind of penalty. So being able to monitor this stuff in real-time is pretty important.

MR. HIRST: Ross, I want to bring this to the transmission, which is the subject of the meeting. There's a lot of interest, as you well know, in non-transmission alternatives to help solve transmission problems. You've heard this morning about the use of suitably located generation. And I think your point is that these load response programs can also serve as alternatives to transmission.

From the point of view of the transmission planner, and more broadly the RTO, what is its responsibility? Is it enough for it to put out a transmission plan that says, Look, as you pointed out, here's a problem in Boston, here's another one in southwest Connecticut? If you can give me some load response there, that would be great, or does the RTO need to go further and actually pay for these load responses? In terms of transmission, what's your sense of where, you know, to go?

MR. MALME: Well, I think -- I think at a minimum what needs to happen is load needs to be treated from an economic standpoint on this -- on a level playing field with generation. In many cases, that's not -- that's just not true today.

And to the extent that -- that that load can be a replacement for transmission or generation capacity, I think the load should get paid for that.

MR. HIRST: So you're saying that the RTO should be willing to spend a dollar on load response as it would on a conductor or transformer?

MR. MALME: Yes.

MR. GLOTFELTY: I'm trying to figure out who actually participates in your program. Is it residents, commercial, industrial? Is it only those who have a contractor obligation to the power?

We have -- we're trying to go through the scenario in our minds with restructuring legislation in Washington, and it's hard to, from our perspective, impute a contractual obligation to power to a residential consumer from a governmental perspective.

Is that an issue that you have or --

MR. MALME: From our standpoint, I think we're indifferent on that issue. We're -- we're delivering a product, whatever business rules are created. In this -- in this particular example, we're delivering this product to customers that can give us as little as a hundred kW. In fact, they aggregate up to a hundred kW.

There's -- in Maine, for example, there's -- they're aggregating four or five customers at a time to get us 200 kW. I think there is a technology limitation saying, where does it -- where is it economic to go down to, what size load? You know, hopefully we'll get down to the residential level, we're not there today, but I think we're certainly down to the -- to midsize commercial-level customer.

MR. GLOTFELTY: How do you -- so is the power under contract or not? I mean, maybe commercial customers, small commercial customers, they don't have a contractual relationship with the utility. Correct?

MR. MALME: In some cases, it's a contractual relationship with a competitive supplier. In some cases, they're operating under a -- under a tariff.

MR. GLOTFELTY: I guess my point is, how do you know how much power you're going to get? How much power do I know I have to sell? Is it on a peak -- on peak amount or is it an average?

MR. MALME: It's what amount that you believe that you can deviate from your baseline.

MR. GLOTFELTY: Okay.

MR. CARRIER: I have a few questions on this also.

I find it very interesting that we're starting to get into this area now, and I just want to know a little bit more about the success of your program. What do you -- I mean, your goal was short-term, I guess 500 megawatts in the program. I was wondering what you had now in the program.

MR. MALME: Yeah. We -- the program was started June 1st. We got started late. Okay. And so we've been, you know, trying to play catch-up through most of the summer.

One of the things we learned in New England, and I think this is no big secret, is when we designed -- the program was designed, the economics for the customer probably were as favorable as they'd like them to be.

So if you look at the economics in New England versus California or New York, for example, those economics in those two states are substantially better. And I think you will be seeing the ISO going to FERC here within a matter of -- NEPOOL and FERC within a matter of weeks with some -- with some improvements to that program.

So today -- there's less than a hundred megawatts today that's signed up and we're, you know, focusing on trying to get that 500 level by next year.

MR. CARRIER: And of that hundred megawatts, how much of it would be for the call option approach versus the voluntary approach?

MR. MALME: Yeah. The -- and that's -- the primary issue here is the economics strongly favor the economic approach as opposed to the call option approach, so I think you'll see, going forward, that there will be a greater economic incentive for customers to enroll into the -- into the call option approach --

MR. CARRIER: And how is that --

MR. MALME: -- from a reliability standpoint.

MR. CARRIER: And how is it divided down, the hundred megawatts?

MR. MALME: It's heavily skewed towards the economic. It's probably 90 percent economic today.

MR. CARRIER: Okay. And I was wondering if -- what -- I noticed on the numbers that you provided up there, you indicated there was a -- 191 megawatt or something during the summer peak that you were able to attribute to this program.

MR. MALME: Those are megawatts hours.

MR. CARRIER: Oh, those are megawatt hours. Okay. I was wondering how that compared with the 100 megawatts.

MR. MALME: Yeah.

MR. CARRIER: Also I was wondering -- you know, we did have some very large peaks in New England this summer, and I was wondering on that -- the call option approach, whether you saw people following the time when they were called -- whether there was a dropout.

MR. MALME: Yeah. The -- the -- the actual performance of the system, when customers got called, was very good. And, Trey, I don't recall the number, but I think we were up around 70 percent, something like that, when the customers got called, they were -- they showed up. So that's about the performance we received.

MR. CARRIER: Now, does the -- does

the system operator actually control the cuts to the -- these customers or are they controlled by the customers?

MR. MALME: In the -- in the call option approach, the operator at the ISO control room has got his finger on the button calling for it.

Now, in this particular case, what he's doing is sending out a notice over the internet to a -- to the -- to that end-use customers that they need to curtail or they need to turn on the generator. So we're looking here at either -- either straight curtailment or generation. All we care about is the meter slowed down so...

MR. CARRIER: Now, for the 30 percent that didn't respond when called upon to do so, what happens there?

MR. MALME: Yeah. And the 30 percent that didn't respond, those were primarily folks in the economic program that, you know --

MR. CARRIER: Thank you. Any other questions?

Thank you very much.

MR. MALME: And we will be submitting written comments on your website.

MR. CARRIER: Also, do you have copies

of your slides that you were using?

MR. MALME: Yes.

MR. CARRIER: If you can provide it to the reporter there.

MR. MALME: Certainly.

MR. CARRIER: Thank you. Our final registered is Steven Herling with PJM Interconnection.

MR. HERLING: Good afternoon. I have not prepared any specific comments, but I have some observations from all the various speakers earlier today, and I'll try to prepare some comments and send them to you later.

Based on what we've been doing -- I'm responsible for the system coordination division at PJM, which includes both capacity adequacy planning as well as the transmission planning functions and the generation interconnection procedures at PJM, so my observations are based on some of the things we've been working through over the last two to three years in establishing a planning process, some of the things that have worked, some of the things that have not worked so well.

You know, obviously we've had a significant transition from the older concepts of integrated resource planning, in particular in the northeast, you know, with all the changes that have taken place, we have moved pretty far from those integrated resource planning concepts.

The generation market is very much competitive now. Within PJM, we have, I believe, received now over 250 requests for the interconnection of new generating resources in approximately two years. That's probably 70 to 80,000 megawatts of new generation. We currently have 60,000 megawatts of generation in PJM.

So, you know, clearly if all that were to be built, we would have more new generation than we have generation today. You know, one of the primary functions of a planning process these days, and I'm not saying this is a good thing, but this is what we've been through in the last two years, is to simply process the requests that parties are making, not just for generation interconnection but for firm point-to-point transmission service, because we are obliged through the tariff to receive and process these requests and accommodate these requests according to timelines that are specified in the tariff.

One of the things that we are

wrestling with now -- and our next plan that, you know, we're developing over the remainder of this year is intended to get us back to something closer to integrated resource planning where we're looking at some of the operational performance issues, some of the congestion issues.

And in the plan that we're working on right now, we intend to try to hit at least the five or six heavy hitters, if you will, in the PJM region in terms of either operational performance or congestion on the PJM system in addition to probably another 50 or 60 generation requests in our current queue.

You know, over the last couple of years, the two plans that we did get through -- approved and are currently moving forward were essentially entirely focused on the generation requests. And, again, that was largely a function of just the number of requests and the number of megawatts.

The first queue that we processed had 30,000 megawatts of generation. That all came in in a period of months. So we are gradually getting processes in place that allow us to work through those requests, get information back to the developers in a timely fashion, and get them to make intelligent business decisions about where to put generation and where not to put generation.

We are very much in favor of the concept of the generation interconnection queue, but you have to -- you have to process that queue very, very quickly. Our cycle is set up around a six-month process. We have not been able to achieve that cycle, but we're getting closer to it.

The point, if you get too many requests in a given area, somebody made the point earlier today the last guy in line gets garbage. You're looking at hundreds of millions of dollars to interconnect. When you're behind three or four other projects, if any of those drop out, the results can change overnight.

The way our process works, you know, hopefully you get the results back to the developer, the first guy makes a decision. There's a greater degree of certainty to the second guy, to the third guy, on and on and on.

Projects that get numbers like $10 million to connect, they typically move forward. 50 million to a hundred million, typically those projects go by the wayside. If you looked at where generation is locating in PJM, it's literally spread across the entire system.

You have a huge number of projects in New Jersey along the eastern part of our system, which the comment was made earlier, that will significantly change the economics and the congestion picture moving forward in PJM.

Most of the congestion issues that we're going to be dealing with in our next plan are more localized in nature. It's a lot easier when you take a local area of the system to know whether there is a likelihood of generation moving into that area or not and whether, even if it does move in, will it resolve congestion?

Areas where we typically get into our various operational procedures on a greater frequency, those are the ones we're going after. We want to reinforce the transmission system to improve the operations in the area and to improve the economic performance in the area.

If you'll look at broad interfaces, like our eastern interface, you know, we may have a hundred generators that want to locate east of that interface. It's almost impossible to put together a credible transmission plan to reinforce that interface until you know a lot more about those generators.

Generators make decisions month to month. Major transmission reinforcement will take years to put together and move forward. So until the dust settles a little bit around the generation interconnection process, you know, obviously we need to look more at the system from a global perspective, but our most immediate concerns, looking at the operational performance and the economics, will be the more localized areas that are easy to get your arms around and easier to understand the dynamics of the various drivers.

We will introduce, where possible, generation as a solution. But, again, that's market-driven. You know, we identify a problem. The generators come. We integrate that into the plan. If -- if load response programs continue to evolve, obviously we've got to integrate that into both operations and planning.

New technologies. We have primarily been looking at the implementation of new conductor technologies. We're out of -- a lot of work with some of the newer conductors in PJM, I think it's ACSS, the sagless conductors. We're finding we can get much better utilization of rights-of-way by reconductoring, you know, with some of these new sagless conductors.

We have really not had much time yet to look into things like FACTS devices and some of those other technologies. We are talking, though, to distributed technology -- excuse me, distributed resource people but mostly in a pilot kind of a format.

We are continuing to work through a number of other pieces of the -- of the planning process. We should -- based on the compliance filing we made a couple of weeks ago, we'll be starting some stakeholder process around how to introduce economic reinforcements to the -- to the planning process, merchant transmission. And the first thing we're actually going to be doing is standardize generation interconnection agreements. It should start up in a couple of weeks.

And somebody else was talking a little bit about the gas industry. We have begun to make inquiries with some of the gas infrastructure people in our -- in our area to develop some form of a focus group, if you will.

We're finding a big disconnect between

the ideas that generation developers have and how gas pipelines are getting built. The -- our planning process needs to bring some of that information together. Individual developers are talking to gas pipelines, obviously, but we need the gas pipeline people to see the broader picture from -- from our perspective in terms of where generation may or may not be locating.

So, again, I'll try to organize these thoughts a little better and then put them on paper for you. But if you have any questions, I'd be happy to take them.

MR. CARRIER: We appreciate that. David?

MR. MEYER: Is your planning process designed in specific ways to try to anticipate and ease siting problems, that is, to focus on alternatives so that --

MR. HERLING: You're talking about generation siting or transmission siting?

MR. MEYER: No. Transmission.

MR. HERLING: I would have to say not specifically. So far we have, I believe, about $700 million worth of infrastructure improvements that have been approved in our plan. Virtually all of that is improvement to existing rights-of-way.

There may only be ten to 20 miles of new rights-of-way in that entire plant. You know, we work very closely with our transmission owners to identify solutions that optimize the existing infrastructure, so in that way perhaps you could -- you could argue that we're trying to minimize siting issues --

MR. MEYER: Yes.

MR. HERLING: -- by eliminating the need to pursue siting. And obviously we work very closely with our state commissions when -- when we believe that there will be siting issues, but to date our -- the development of our plans has been largely driven by the availability of opportunities to increase capability of existing rights-of-way.

MR. CARRIER: Can I follow up on that a little bit?

MR. HERLING: Sure.

MR. CARRIER: Is that approach being taken because it's the easiest way, meaning you avoid the siting process, or is it the most economic solution?

MR. HERLING: It's kind of a combination. We have, on a number of occasions, looked at multiple alternatives. And when they involve rights-of-way, you know, we typically review what historical issues our transmission owners have had.

Most of the -- you know, most of the new ideas for improvements to the transmission system aren't really new. Our transmission owners have kicked them around for years. So they typically have some history about the ability to obtain rights-of-way in particular areas.

So in most cases, it's more of a balance of cost and risk associated with one option versus another. And where we have ended out in most cases is avoiding the new rights-of-way.

MR. CARRIER: This approach you take where you kind of go incrementally with your transmission improvements based on your -- your interconnection requests, is that the most efficient way to proceed or would a more efficient way be to think in terms of when making an improvement to provide some excess capacity there to accommodate future generation needs?

MR. HERLING: Yeah. Actually the process typically looks at, you know, where there are opportunities to introduce greater capability than is required for a specific request. You know, we do evaluate those opportunities. That's really more a cost allocation issue than anything else.

Developers are only responsible for the minimum upgrades to accommodate their request. Where practical, though, we will pursue what we believe are more effective solutions for the region than what is simply required for the generator.

MR. CARRIER: And who bears those additional costs?

MR. HERLING: Transmission owner, and ultimately those can be pursued through revenue requirement. You know, they can introduce them into revenue requirement at their discretion.

MR. CARRIER: Other questions? Yes.

MR. OVERBYE: I've got a question about -- you were saying for new technologies you're primarily using a new conductor that's sagless. Is that right?

MR. HERLING: Well, it's referred to as sagless. I think it's ACSS as a stronger steel core that reduces sag. You can allow it to go to a much higher operating temperature under load without perceptible sag that typically is what limits the current carrying capability of overhead conductor.

We're finding we can get significantly more out of a particular right-of-way. The biggest problem is weight. You have to look at your tower structures carefully to see how much you can support without -- you know, once you go -- once you have to re -- once you have to redo your towers, the cost gets fairly significant. So if you can get the conductor on the same towers, you can get a lot more capability at reasonably low cost.

The next step obviously is stronger towers. That gets to be, first of all, a lot more work and a lot more expense.

MR. OVERBYE: And you said for you FACTS -- you just don't see it as economical?

MR. HERLING: No, no, I didn't say that.

MR. OVERBYE: Oh.

MR. HERLING: I said we really haven't had much time to look at it. The biggest -- the biggest problem with our planning process and FACTS is a timeliness issue. We get a request that the generator wants to be in service in three years. We have to have a viable plan that can be implemented in three years.

FACTS -- you know, my own personal

opinion is that we will look for opportunities in the future where we can introduce these kinds of devices to solve operability problems first. And then, as we gain more comfort with them, then we will decide what to do with them in a planning perspective.

You know, things like phase-angle regulators, for example, we have used in PJM. You know, typically first you use them to solve an operability problem and then, as you gain more comfort, you perhaps will use them in the planning process.

We typically don't like to constrain the system in the planning process if you don't have to. So you may want to introduce the concept of a series reactor, but it's sort of a last, you know, option, if you will. I prefer not to constrain a healthy transmission corridor with a series reactor, but if it's the only way to solve the problem, then obviously that's what you have to look at.

From an operations perspective, there are lots of things you'll do in operations to preserve the integrity of the system. And I could easily see us pursuing FACTS in that context. Then as you gain, you know, operating experience, you pursue it in the planning context.

Load response is another example. Distributed generation, I think, is another example. As we gain operating experience with these tools, then we'll decide, what do we do with that, in the planning context.

MR. ALVARADO: I have two questions. The first is, do you see any value of exploring -- would you be interested in somebody exploring the possibility of not only just looking at the PJM region but looking more at inter-regional traits and the need or necessity or desirability for possibly expanding on the capability for -- you know, essentially, let's say, go back to PJM and PJM to Florida or just longer distance and interpool -- or inter-regional trading?

Are you looking at that? Is anybody looking at that? Are you -- you know, there's been something that perhaps this panel could suggest it needs to be looked at or something of this sort.

MR. HERLING: Yeah. We have tried to take steps in those directions with some of our neighbors, obviously with New York and New England and Ontario. We've begun to have discussions with some of the parties to the west and south of us as well.

The trick, I think, to developing those types of plans is that the -- and my example before of going after the fairly local operability problems or economic problems is it's a lot easier to understand the variables. There are fewer, first of all, and you have more control over them.

So you can propose an upgrade to a fairly localized congestion situation and have a pretty high degree of certainty that you'll be able to move forward and that it will still make sense when you get done.

The problem with larger inter-regional economic solutions is that the markets can turn around on you from year to year, and it's very difficult -- it's certainly not impossible, but it's very difficult to project where the economics will take you and, therefore, where your cost benefit analysis will take you when you look at these, you know, broader inter-regional planning efforts.

I certainly would encourage some of that activity to move forward. The hardest part -- in our planning process over the last two years, everything was real concrete. It was all driven by the tariff and reliability requirements.

The plan we're working on now is

introducing things that get grayer. You have operations issues. You have small-scale economic issues. What you're referring to really gets tougher to -- to nail down when you have a good solution and when you don't.

And I'm not saying don't go there. I'm saying let's do some of the evaluation. Typically you can do a needs assessment, look at potential solutions. It's that last step when you do the cost benefit that's going to be tricky.

MR. ALVARADO: (Unintelligible) recognize that problem, yes.

My next question is a little bit on -- I don't know exactly how to phrase it, but clearly your -- your system sends very strong specific price signals so generators know what's happening, what's likely to happen and all that.

The construction of one transmission line could drastically change the congestion patterns certainly either in an entire region or in a -- at least in a substantial section of the region.

Do you do -- and there's really two issues with that. One is that when you introduce one of those, there's going to be winners and losers and, of course, the process by which you introduce it, are you going to do it in a glass bowl where everybody sees it or are you going to -- do you keep it as much of a secret as you can until it's announced?

Any in between, I think, can be highly unfair and subject to great controversy. So which of the two models do you use or do you intend to use?

MR. HERLING: Well, yeah. Our planning process I think right now is the glass bowl approach, and that is our intention. You can't possibly, as you say -- with the winners and losers issues around, anything that gets to economics, you have to do it in an open forum. The scope, when you start such a study, has to have input from -- from a wide variety of stakeholders because the decision making at the end of the -- at the end of the day is going to be based on an evaluation of costs and benefits and everyone's perspective on that will be different.

With reliability, it's usually more crisp. You know, you have a violation. You have to fix it. There's three different ways to fix it and we decide which one we prefer. People can disagree, but they typically don't disagree about the nature of the problem going in.

With economics, it's much, much more

difficult to get consensus as to what you should and should not be doing. So it has to be done in a very much open forum. The -- you know, again, how you start to make those decisions -- even reliability-based upgrades can change the economics significantly.

I -- I don't believe right now -- we have a certain amount of siting that's based on locational prices in individual areas. I think the bulk of the decision making around siting in PJM is mostly a function of the existence of the markets themselves.

Locational pricing typically provides a mechanism for recovery of fixed costs in addition to variable costs that the developers appear to like. A handful of projects are siting based on locational problems and the ability to use the -- you know, get on the constrained end of a problem and help solve that and make some money obviously.

MR. ALVARADO: Of course, if you solve it too well, you won't make any money.

MR. HERLING: That is the -- that is one of the issues. With anything you build, you will typically eliminate congestion or some amount of congestion certainly.

MR. HIRST: Steve, one topic that hasn't come up today, and I'm kind of surprised that it hasn't -- I think Phil this morning mentioned it very briefly, is merchant transmission.

I think you did a great job of outlining some of the difficulties in transmission planning. It's interesting that from the ISO's perspective your comments in many ways paralleled with what Perry Stowe said this morning from the Southern Company's perspective about the difficulties and how you're driven by all the interconnection requests.

Is it possible to just turn this all over to market (inaudible) like congestion pricing in terms of new generation and add management program to merchant transmission? I'm asking particularly about merchant transmission.

MR. HERLING: The -- the dilemma with merchant transmission is it's not clear yet what the recovery mechanisms are going to look like, in particular for AC, if there ever is such a thing as merchant AC transmission.

DC, it would appear that the recovery mechanisms are somewhat better understood, so you see a number of parties dabbling in DC projects. And that's the first area we need to address at PJM because some of those parties have contacted us and want to look at some of those projects.

I honestly don't have a good sense yet for how merchants transmission would work with AC. You know, what -- what would really incent someone -- you know, what could we put in place that would incent someone to invest as a merchant transmission developer in AC facilities if they get the kind of recovery that is in place today?

Now, if you move toward incentive-based ratemaking, for example, somebody suggested earlier that if you can solve a congestion problem, there's a way to quantify that and get some of that money back to the developer, then I think you have something.

Performance-based ratemaking, I don't know. That's simply you do a better job with your -- you know, having your facilities available, you get a little more money.

I think -- I think if you go after the concept of solving economic issues and finding a way to get some of that money back to the transmission people, you might be able to get merchants in, too, but remember, and it was just said a second ago, if you solve the congestion problem, you know, the load is happy. If you give some of the money to the transmission developer, he's happy, but some generator somewhere is not making as much money, so it's not a win-win-win for everybody.

MR. MEYER: Paul, earlier in response to a question, you said that the uncertainties associated with analyzing possibly inter-regional transfers were much greater than some of the smaller-scale problems.

Tell me more about those uncertainties. Why is this so much more?

MR. HERLING: Well, you know, if you look at the last couple of years, you know, where were the prices really high? And a couple of years ago, they were high out in the Midwest and, you know, we've seen some higher prices up in the northeast.

Our transmission is -- you know, you get a lot of transmission reserved in one direction one day and then everybody wants to go the opposite direction the next. Until you know better how much generation is going to get built, you know, and how soon, you know, the capacity markets alone in any given region are going to be all over the place.

PJM's capacity market today is

reasonably healthy. We have a -- you know, a reasonable margin over what we absolutely need, but we're not so fat that -- you know, that the prices are sitting at zero and are going to stay that way.

And let's face it. If we add a few thousand megawatts over the next six or 12 months, some of those developers are going to be looking to New York or to the west or to the south for opportunities to sell that capacity if they can get off of our system.

So it's going to take a few years for the generation interconnection procedures everywhere to get fully mature and for generation to get in the ground and the markets to get fully mature so that you can determine where are the opportunities to move energy over long distances.

Right now, it's too reactionary to, where is the problem today and where is the generation today to deliver to that problem? And I don't know that you could predict that that same set of circumstances will exist in 12 months or five years.

So it -- it would be very difficult for me to justify, you know, hundreds of millions of dollars worth of transmission to be recovered over 20 or 30 years based on a model where I couldn't even predict the market conditions two years out.

MR. CARRIER: Thank you very much, Steve.

Steve was our last registered speaker. I would like to open it up. Some of you might have heard some -- something discussed earlier today that you may want to comment on. And I see a hand go up right away.

I would ask you, please, to come up to the microphone. And since we -- we don't have your name written down here, then I'd ask that you identify yourself and your organization.

MR. CONROY: Good afternoon. My name is David Conroy. I'm manager of system planning for Central Maine Power Company. Central Maine Power is a member of the New England Power Pool and the Northeast Power Coordinating Council.

I'd like to offer some miscellaneous comments based on the white papers that were handed out on the table outside, but, first of all, in a more general sense, I'd like to ask and answer the question, is a federal transmission grid necessary? In my view, no.

Is it advisable or beneficial to the

United States? And I'd say maybe, but I personally remain a skeptic and I believe that's the object of the study that you folks are embarking on.

Another point I'd like to make is arguably we already have a national transmission grid. On our web page, we describe the eastern interconnected network as the largest machine in the world. And our frequency recorders outside of Augusta, Maine pick up disturbances in Virginia, Ontario and elsewhere across the network.

Another aspect I'd like to point out, and to reinforce something that Phil Fedora of NPCC had mentioned, that the eastern interconnected network is an international network and so we do need to consider our Canadian neighbors and, for that matter, Baja, Mexico, which is also interconnected in any assessment of a national grid and implications and recommendations.

The largest outage, I believe, in history -- blackout in history originated in Ontario and propagated through New York, New England and parts of Pennsylvania.

Now, going to the white papers, I'd just like to take some terms and provide some comments on those. I'll start with transmission planning and the need for new capacity. And on the first page there, it says, this shift from planning connected by individual utilities for the needs of their customers to planning connected by RTOs for regional electricity markets. I'd just like to reinforce that planning has been and I believe continues to be and should be a coordinated effort at all levels.

At Central Maine Power, we plan for our own system for -- we participate in planning for the NEPOOL system and for NPCC as well. I think it's important to continue, and I think it needs to be a team effort, if we ought to assure the reliability of the interconnected systems.

The next section is, to what extent should RTOs plan solely to meet reliability requirements versus expansion for commercial purposes? I say that's a good question and I'll leave it at that. I don't know the answer.

In the next section, to what extent can private investors rather than RTO planners decide and pay for new transmission facilities? And I think in our part of the world in the northeast, we're seeing the beginnings of that. We've got both the Neptune regional transmission system and

Transenergie, which have projects being proposed and developed in the northeast, and so I think we'll have real-life examples of that as they pan out.

The next section, congestion costs. Are historical congestion costs a suitable basis for deciding on transmission investments? And I would say that they are a basis, but they should not be the singular basis. It is only a factor in the decision in the analysis.

I would give as an example, this summer, during the summer peak period, because of all the new generation we've interconnected in Maine, over 1500 megawatts worth in five projects over the last few years, having gone through our own queue process and wrestled with that, we had seen congestion on the Maine interface and exported.

That was borne out in the analysis that I saw New England did in the regional transmission expansion plan. That expansion plan also projects the congestion to be reduced on the short term because of additional generation development in the importing areas of New England. So a historical basis cannot be the only basis for consideration.

The next page, Should RTOs overbuild

transmission facilities in the anticipation of future need? My answer to that would be no to just simply overbuild. I would say appropriately build, but that's probably what that was intended to say anyway.

While we're on the page, planning data. Who will provide the data? And I think we're doing that on an ongoing basis today in the open access re-regulated and not vertically integrated world at least where I live. And as far as the data on the generating units, the generators provide that and they provide that to ISO and to us, the individual transmission providers.

As far as loads and load shapes, that's something that we are responsible for as local transmission providers. I'm not sure if the question was intended to go deeper than that.

Next on the siting and permitting, my big caution there is that as we -- or as you pursue an evaluation of the federal siting and permitting process that it not simply be one more layer. If it is one more layer, then it is a detriment to development rather than a help, but I'm sure you know that.

The other aspect I'd like to discuss

on siting and permitting is the specification of the size. For instance, 230 kV is mentioned, or larger, as a possibility. Also length in miles is a possibility.

I would just be very cautious in trying to draw a line only because many times underlying facilities are the ones that are limiting for major interfaces and it can be lower voltages in very short lengths that are the limiting elements to additional transfer to capability.

Next, alternative business models for transmission investment and operation, on the third page there, there's a mention of Transmission investment decisions cannot effectively rely on market mechanisms. I would say that's probably in part because of regulatory incentives or detriments to additional transmission investment.

And, again, there's discussion of market forces that will draw significant entrepreneurial investment into transmission capacity. And I would just point to Neptune and Transenergie in our part of the world as entrepreneurial ventures and also with the publication of -- of the New England regional transmission expansion plan, that basically is a road map to point out opportunities to development.

So over the course of a year, we'll see what market forces may respond to that. Also, I'd like to point out at least in some parts of the world, FCRs or FTRs, or whatever mechanisms they are called, can be a detriment to investment and we have to look at who pays and who benefits from additional transmission investment.

Also, there is uncertainty now in the marketplace because of the development in the northeast RTO and the other RTOs, how that would be treated, so right now there's just plain uncertainty in how that all pans out.

Transmission system operation interconnection. Assurance of reliability has generally taken place on a company-by-company basis. I guess I would argue that reliability, I believe, at least in our part of the world, has been very well coordinated and we are responsible on both a company pool and a regional basis, reliability council basis.

I would advise caution after seeing the statement that protocols for system reliability would have to be altered or replaced with a system that is compatible with these larger markets.

I believe we have good reliability protocols in place. We have not seen widespread or cascading outages. I think any modification or replacement of that we need to tread very carefully.

Reliability management and oversight. There is a statement made, Combining individual electric systems and on integrated network increases reliability and saves money. And I guess I would only make the statement that that remains to be seen. Rather than a statement, I think that's something that will have to result from analysis. And I would recommend that both the analysis and the assumption behind that be published and provided as a basis for that statement.

And as a -- as a final comment, in new transmission technologies, the opening sentence, The transmission -- electric -- electricity restructuring envisions the transmission system as flexible, reliable and open to all exchanges, no matter where the suppliers and consumers of energy are located.

And I would argue that as a result of the FERC Oxboard order of October 29th, 1998, which I was party to, disputes that. And we had originally proposed in New England to assess generation interconnection requirements relative to deliverability and FERC in their -- in that decision, basically resulted in minimum interconnection standard which is a let-congestion-build approach, add new generation but interface capability is not changed dissociative of that.

Those are my comments. Thank you.

MR. CARRIER: Thank you very much, David.

MR. GLOTFELTY: I wanted to make a comment about your first comment, which is --

MR. CONROY: Okay.

MR. GLOTFELTY: -- a national grid and make the point, we're not talking about a nationalized grid or a federalized grid. We're talking about a national grid of -- that's owned by private entities and non-profits that operates like a similar entity, but there is no intent on our part -- the federal government's part to make this a federal grid.

I will say that in the early '80s, based upon a number of bills that were introduced in the mid '70s, there was talk of creating a nationalized grid, a -- I don't know if it was the National Transmission Company or the Federal Transmission Company, to do that, to create a major backbone around the US owned by the federal government.

That is not what we're trying to do here, so I just wanted to make sure that you and others in the audience knew that.

MR. CONROY: Thank you.

MR. CARRIER: Do we have any questions?

Thank you very much for coming all the way down from Maine, my home state.

MR. CONROY: Thank you.

MR. CARRIER: Do we have anybody else that would like to speak?

Yes, please.

MR. MORRIS: My name is Scott Morris and I'm the legal and regulatory policy advisor for Commissioner Jim Sullivan, who is the president of the Alabama Public Service Commission.

And I just wanted to make a few comments here today. And first let me reiterate that I am a -- while the Commissioner has unleashed me to speak on his behalf, I do not speak for the entire Commission in Alabama.

First of all, I would like to thank the commissioner from South Carolina for his eloquent and thoughtful comments. That would provide an excellent foundation for a position that I suspect most of the southeastern commissions would subscribe to.

That being said, I have a few concerns that I really haven't heard addressed here today, and these are primarily in terms of security, and what I'm talking about is the physical security. And as you know, the world changed on September 11th.

And really these aren't comments. These are questions that I would ask that the department ask itself and consider as it moves forward in this process.

Number one, are you working with the Office of Critical Infrastructure Protection to analyze the current vulnerabilities and the impacts of any proposed changes to the transmission grid?

Second -- there was a mention made earlier by one of the representatives from Southern Company about planning for a single-mode failure, and he had out there, in parentheses, the term "terrorist."

Have you considered the potential for a coordinated assault against the grid? Have you considered and done analysis on the security benefits in redundancy, both in terms of control, physical assets and key personnel?

And I would comment that in my experience, efficiency tends to eliminate redundancy and make each element in the network more critical to the function of that network and thus a more valuable target.

Have you considered the security risks and concentration of key assets, whether they be transmission or generation? And this has implications beyond the physical security.

I'll take an example of our own state, Alabama, and I know this is going on as well in Mississippi. We're getting a tremendous amount of merchant generation built in that Gulf Coast region to take advantage of the abundant supplies of natural gas that we have in the Gulf of Mexico.

If -- I can conceive in the future, you know, if -- based on some of the proposals that have been talked about, a significant, you know, generation down here that is serving load possibly several states away, maybe up into the Midwest, and the Midwest becomes competitive on that load, if you have one hurricane that can come in and, you know, for a considerable amount of time take out a significant amount of that generating facility, you're going to have impacts, you know, potentially on into the country.

The more depend -- the more dependent you are on, you know, isolated or expanded networks to get from generation to load, the more vulnerable it becomes.

Also the transmission, if you have transmission concentrated perhaps in, you know, one right-of-way or contiguous rights-of-way. We have a lot of tornadoes in the southeast you have come through there and you might take down, you know, a very critical node.

If you become dependent upon, you know, a single right-of-way multiple transmission lines into one area of the country, it could cause considerable problems if you become too dependent on that one link to the system.

And, finally, have you considered that exclusive or primary federal siting authority might actually make it more difficult to site transmission in certain states? I'll give the example of Alabama.

Alabama has a very liberal eminent domain statute. It is very easy for companies to come in and exercise eminent domain for the economic good of the state. It is very easy to site and build industrial-type projects in our state.

And I would just offer that having had some legal experience dealing with the environmental impact of statement requirements and all the environmental process that you have to go through in a federal process that you might actually -- in many regions of the country, were the federal government to take the primary role, you might actually be slowing down the process and not speeding it up.

And that concludes my comments.

MR. CARRIER: You know, just for the benefit of everyone here, including you, I'd like to address a few of these questions now. I think these are very good questions.

Your first one regarding the -- the change that has occurred over the last couple of weeks as a result of the unfortunate events of September 11th, that is an area that we recognize, you know, is going to impact, you know, the study that we are doing. And we've asked each of our study performers in these six issues that they're looking at to take that into consideration, the need for secure -- physical security and cyber security of our facilities.

And we have given it some attention. I'd point out that I do have a very significant role in this study, I'm director of Office of Energy Emergency in the Policy Office at the Department of Energy. We do work very closely with the Office of Critical Infrastructure Protection at the Department of Energy and we have somebody from that office who is working directly with us as kind of helping provide some guidance to the study team.

I would also note, you know, some of these other questions you raised do raise very good issues, and I'm sure we -- we -- we will take that into consideration in our study.

The -- the last one that you raised regarding the federal siting, I think that's a very -- a very good issue as well. I -- I used to work at the Federal Energy Regulatory Commission and we dealt with the hydroelectric licensing, and that process is not a simple one and we get -- we got complaints about it all the time. Hopefully we can simplify that a little bit now, but it is a very good point you raised.

I would note that many -- talking in terms of the federal role being a supportive or a backup role to the states in the case like Alabama or whatever, you know, siting and the eminent domain resolve the problems and there would be no need for the federal government then to step in. So it would hopefully complement, you know, what the states are doing, and I think that's an approach that we're considering.

Any other comments?

MR. GLOTFELTY: Yeah. I want to address the same two issues very quickly.

A lot of the issues that we have to deal with on critical infrastructure protection are challenging to the federal government because right now there are very few rules and very few regulations that give us the authority to do so.

We have regulations on -- due to FERC on transmission costs, none of the siting issues, very few generation issues. How we protect these is something that we're going to have to use the (unintelligible) pulpit for more than anything.

There are some issues. We have been working with the House and the Senate, Energy and Commerce committees. In fact, today and tomorrow, we're briefing each committee classified -- not classified, they're closed hearings on specific issues, specific critical infrastructure issues regarding our energy infrastructure.

So it's clearly front and center at the Department of Energy. How we quantify all of that in this study is yet to be determined, but it will be addressed in this study.

Secondly, on federal siting, I want to say that from my standpoint federal siting puts the incentive in the wrong place. Federal siting should be a state decision. It should be a local decision.

The reason it has elevated to the federal level is because, as you all know, there are a few lines -- a few bad apples that haven't gotten sited. Some of that is due to state regulations that do not allow decisions to be made to take into consideration the economic impact out there. There are a host of regions -- reasons. That's the main one.

But what I don't think we should do is try and develop a system where every state regulator gets to vote no and the ultimate decision goes to the Federal Energy Regulatory Commission. That puts it in the wrong place and that is what we do not want to do.

We want to keep pushing the decisions

down so it's a regional interest decision that is made. And only if the region can't agree do we take action, but clearly we don't have that authority now and clearly it is the most -- one of the most hotly contested state and federal issues that's being debated in Congress right now.

I appreciate your comments.

MR. CARRIER: I just had Joe remind me of something that I should mention regarding security, and, that is, that we do work very closely also with NIPC and, you know, one of the big concerns in dealing with security is that in dealing with it you don't want to divulge your vulnerabilities.

MR. MORRIS: Exactly, exactly.

MR. CARRIER: So we use mechanisms like NIPC in order to communicate with the industry, to identify vulnerabilities and security risks and address them jointly both from the federal side and the private sector side. So we do work with that mechanism.

Following the events of September 11th, we did immediately stop participating in daily conference calls with NERC and the regional system operators to assess, you know, any threats or potential threats to the electric transmission grid.

So we do work very cooperatively with the industry.

Any other questions or comments?

Thank you very much.

MR. MORRIS: Thank you.

MR. CARRIER: Anybody else would like to make some comments? Yes.

MR. OSBORN: My name is Dale Osborn. I'm the lead transmission expansion planner for the Midwest ISO. I have a couple of comments. One, is the comments I'm going to make do not apply to SERC or PJM or the New York area. It applies to Midwest.

Transmission requirements in different areas of the country are different, and you need different solutions for different areas. But in the Midwest, there happens to be an opportunity that could be addressed.

The opportunity is that the transmission system there predominantly is 345 kV and it's spread out into small local transmission areas with weak inner ties. On the west side, there's a north-south set of lines that's strong, on the east side, there's a north-south set of lines that's fairly strong, and then it connects on the east to the 765 AEP in other systems.

The point is that in this area there's

quite a bit of gas, there's quite a bit of coal and there's quite a bit of nuclear, and it's difficult to move that generation from one area to the other. There's also a point in history where they've about worn out what they've got so, you know, they've got to do something new.

And a point in history is -- that may occur sooner or later, that they need a higher voltage overlay to tie the area together. My point is, is that if this overlay were built for a separate purpose from the way the other system is built, you may have something that would appeal to certain factions.

The point is, is the underlying system is built on minimum cost of service to the consumer and for reliability. If you build an overlay system, you could build it with a different criteria. You could build it with the market criteria suitable for generation, including coal and nuclear.

The overlay system would have to be controlled for access. It's a dirty word, but it's -- it works this way. The overlay system is like the interstate. You have certain places you can get on, you have certain places you get off. You might drive certain big trucks through certain areas where you probably wouldn't want to do it through a residential neighborhood.

If you build a system like that, an overlay from let's say Manitoba to Texas, a pretty big area, that would be a federal project, I'd guess. You could transfer power in that region on an overlaid system to any part of that area. You would have access to quite a large market.

Any generator that could access that system would also have a very large market. I would propose that the generators maintain their connections at the lower voltages and they have a primary market that they locate in, but that they would have that local access. And there would be nodes of access. One would be probably a Southern Indiana, Kentucky area where there's a lot of generation. Another would probably be Indianapolis, Chicago, Milwaukee, Northern Wisconsin where the nuke's at, then you go over to Minneapolis, North Dakota, down through Nebraska, Kansas City, Oklahoma City, Tulsa, Little Rock, back through TVA and back to Indiana.

Now, that would all work except you'd use one line, then you'd have the little problem. It's a long ways around there so you have to build some lines across there so if you lose one, you can back it up, so you have to have redundancy.

If you did that, then when you lost one line, you would have the redundant system there and you wouldn't affect the underlying systems. Otherwise, you'd de-couple the overhead system from the underlying systems. People could continue to build the underlying systems as they are today at a low-cost, reliable method and they could also have access to the -- to generation in the entire region.

Now, the way you control that is phase shifters or phase shifter devices. There's different types. One's an old-fashioned phase shifters, the clickety-clack tap changer. You can do that with electronics today or you can use a controllable series capacitor to give you either reactants or capacitants, so you can control the power flowing through these nodes.

You could shift power anywhere in that region by putting it on at a node and taking it off on the node, and the power would be scheduled into the overlying system and out of the overlying system.

If you go on to the overlying system, I would propose you pay for it. And when you came off, you would be on the node. The exact economics, I think people could argue till -- you know, for a long time. But there is a way to do it. There is a place that it would work.

The technology is there. There are problems with state laws. How do you express a need for a generator to get power from one place to another that doesn't serve a local load? That's probably the biggest problem.

There was -- something the federal government would have to do would be help in solving that problem. I just appreciate the opportunity to address it and I thought it might be an idea that may be of interest to you.

MR. CARRIER: Thank you very much, Dan. I think we have a question.

MR. OVERBYE: I do. Coming from Illinois, I'm very interested in this. Is this -- I've never heard of this before. Is this a proposal or --

MR. OSBORN: It's an idea.

MR. OVERBYE: It's just at an idea stage. And by high voltage, you mean 765 kV grid, running that?

MR. OSBORN: 765 or 500, whichever is

most economical.

MR. OVERBYE: Okay.

MR. CARRIER: Eric.

MR. HIRST: Dale, I have a question about the comment you made early on and that was that the Midwest is not the same as SERC or the northeast and so on.

And one of the issues we're grappling with in terms of reliability is should we have North American standards or regional standards or some combination, and should it start at a regional level and go upward to North America and levelling it down?

One of the things that's always puzzled me is I recognize there are differences among the regions, but it's not clear to me why those differences in transmission topology and generation and load would argue for the different reliability standards, and maybe you can comment on that.

MR. OSBORN: In the United States, if you go east of the Mississippi River, most of the transmission there is thermally constraint or based on that, not everywhere but most of the places, like -- I would say from Chicago east and north of Kentucky, in that area.

If you go west of the Missouri River, that is the stability constraint. It's a different operation. It's a different method of designing the systems. And also there aren't very many people out there to pay for these systems.

But if you look at Maine and around that -- around that area, that has probably the highest load per mile of transmission line in the United States. If you go out in the west, probably around Nebraska and those areas, it's probably one -- and South Dakota, it's probably one of the lowest.

When you can stand on a hill and not see anything for as far as you can see, the population is low, and there are places out west you can do that. It's a little harder to do in Chicago where you see a person everywhere you stand.

So the concentration of loads is different. The money available to pay for the systems is different. I think they still basically designed the same NERC standards, the loss of lines, but you have -- people just have to design to a little lower levels in some of these areas because they can't afford it. And systems are designed to have a certain level of reliability and people are willing to accept that in those regions.

MR. CARRIER: Any other questions?
Thank you very much.
Anybody else like to speak or make some comments? Yes.
MR. FEDORA: I'd just like to respond to one of the questions.
MR. CARRIER: Sure. Come up to the mike.
MR. FEDORA: I might have failed -- this is Phil Fedora from Northeast Power Coordinating Council.
All the presentations that were given at our Future Transmission System Reliability meeting in Toronto are available on our website and the panel here may be interested in looking at them and downloading them as they cover many of the topics here. It's www.npcc.org.
But in answer to a question that Fernando raised, in the regional planning forum that we have at NPCC, I gave a presentation that addresses one of the questions he asked, which was, is anyone looking at power transfers from, let's say, NEPOOL to MAAC or from Canada down to MAAC or vice versa?
And that's exactly what the goal of the planning forum is. We were going to have our

meeting September -- another one of our ongoing meetings -- the forum was formed in June of this year and we had a meeting scheduled for the 17th of September that we postponed, due to the events of the previous week, where PJM representatives were invited to that meeting and were planning to participate.

So your meeting is rescheduled for October now. And rather than go through all the details of what we have there, you can see my presentation on the website. And if anyone from the panel is interested in that October meeting to get an idea how at the NPCC level we've been dealing with these wide-area trans-regional issues of transmission, if you'd just contact me and we'll get the details. We haven't scheduled the meeting yet. It's a mid October meeting.

Thank you.

MR. CARRIER: Thank you, Phil.

Anybody else? We have a couple of hands going up.

MR. JACKSON: Bard Jackson with the Rural Utilities Services. And I just had a question on your process of putting the report study together.

Is there going to be any draft and any

other opportunity to comment?

MR. CARRIER: This is the opportunity for the public input. And what we wanted to do is hold this -- these types of workshops up front so we could hear from all the stakeholders we've heard from today and at our other workshops, and so we wanted to get that input up front so it can influence how the study actually evolves and develops.

We will be providing information on our progress on our website and you will have the transcripts of these meetings, these workshops up there and hopefully see some of the progress. I don't see, though, another public process.

I'm sorry. Yes, we do hope that many people will make comments on our website also by October 10th, so that's part of the process as well. But I don't see us distributing, say, a draft report for public comment.

I think what we'll do is have the -- the way we're envisioning this report, looking -- we expected to have individual papers on each of the six issue areas that we've been discussing today and that -- there be a lot of, you know, independence given to those authors preparing those papers.

It won't represent necessarily the

views of the Department of Energy. But using that as input and other inputs, you know, maybe putting emphasis in different areas, the Department will develop its recommendations and put that at the front of the six issue papers and that will essentially be our report.

And at that point, when we issue the report at the end of December, then there will be a discussion, I imagine, on ways to implement the recommendations.

I -- Jimmy noted early on this morning that we are working closely with both the National Governors Association and the Western Governors Association. And you might have seen it in the press recently where we have entered into an agreement with the National Governors Association. I think we're doing the same with the Western Governors. And we will be working closely with them in developing means for implementing our recommendations.

Yes. Also I wanted -- I was reminded to mention that we are also working closely with FERC in this process as well. They have been meeting with us and we are working closely, coordinating with them as well. So we're getting inputs from a number of variants.

I did see another hand. Yes.

MR. SCHAEFF: I hope you don't mind a second time around.

MR. CARRIER: It's all right.

MR. SCHAEFF: It seemed like there was some available time. I'm Gary Schaeff again. I'm director of transmission for MEAG Power here in Atlanta.

This time I'm going to be speaking just on MEAG Power's behalf, not LPPC. A couple of comments that I would just like to try to get across to you as you deliberate on a national grid from my viewpoint, and it's -- first and foremost is a request that you be very certain and be very careful on what you decide that is good for the nation and for America.

I would urge you to be sort of like a doctor and first and foremost do no harm. We are very concerned that in going forward some of the processes in the rush in which people are trying to proceed could do harm.

MEAG Power and most public power are not opposed to RTOs or a national grid or things that could benefit America. However, we don't want to be harmed by being precipitous or rushing into something based upon assumed benefits.

One of the objections that I think many of you have seen in the past from numerous entities is that we want to know for certain it's going to benefit us, not just assume that it will benefit us or benefit America.

One of the things also is that people look at things that on the average it will benefit. Well, on the average is not necessarily a good thing. You can harm a lot of people on one side and benefit others on the other side and still on the average you're ahead, but if you're shooting at a target, if you shoot three feet left and three feet right, on the average you were right on, but still you didn't achieve anything good, so I'd just urge you to look at that.

The stakes are high here. California, in my opinion, thought they had it all worked out and their plan was going to work and benefit everybody. It didn't work out that way. There were a lot of unintended consequences despite good intentions.

So from that standpoint, we would urge that we be very, very careful on how we proceed. A number of speakers today have spoken concerning reliability. As a public power supplier, that is our first and foremost concern. Low economics are very high on our priority list, but reliability is far above that.

As we stretch the grid, as we try to squeeze more out of the transmission grid, we put the grid at more risk, and that's being done now. The grid is being used for things it wasn't intended to be used for. It was built to serve native load.

The stretching it and using it for moving bulk power across grids and systems is not a bad thing, but let's not sacrifice reliability in the process and that, I see, is already being done. If we have RTOs that are incentivized to actually move power and squeeze the most out of the grid, I'm concerned that that will even put the grid at risk versus now our main motive is reliability and serving our customers first.

One last thing I'd like to speak on is a lot of comments I've heard speak about the -- the national grid or the transmission grid becoming like the superhighway system, build it big and build it so that you can move power anywhere anytime without restraints. Well, I for one am cheap. I don't like spending money and wasting money that's not needed or beneficial, particularly when those costs may come down on my native load customers even if they don't need those capabilities.

We currently finance transmission expenditures over 30 to 50 years. There is a long-term risk of paying for those investments. I don't particularly want native load Georgia consumers picking up the costs if we build a massive grid to move power through Georgia, and those people don't come and don't use it and don't pay for it. Somebody gets stuck with the tab if it's not paid for by somebody else.

So we want to protect, whatever we do going forward, the native load customers from picking up the tab for something that may not benefit them. The costs and the risk should go where the benefits go. Whoever is going to benefit and wants the increased capabilities, they ought to pick up the risk and the cost and not others, and that's one thing I ask you to look at when you're going forward. And that's it.

MR. CARRIER: Thank you. Any other comments?

Gary, we gave you the first comments and the final ones as well.

MR. SCHAEFF: I appreciate it.

MR. CARRIER: And I appreciate the cautionary statements that you gave here in concluding.

I would like to thank everybody for their participation. I realize some of you came quite some distance and I know you're all very busy people, but your contributions here, the statements you have made, the statements that you will be filing or submitting on our website, they all, you know, will play a significant role in helping us formulate our issue papers and our recommendations in the study will be issued by December 31st. So I want to thank you all very much and I look forward to seeing your additional comments on our website.

Jimmy, would you like to make any closing remarks?

MR. GLOTFELTY: Thank you.

MR. CARRIER: Thank you all very much.

(Proceedings concluded at 3:07 p.m.)

THE STATE OF TEXAS :

COUNTY OF HARRIS :

REPORTER'S CERTIFICATION TO THE
TRANSCRIPTION OF THE WORKSHOP
HELD ON SEPTEMBER 26, 2001

I, DIANA RAMOS, a Certified Shorthand Reporter in and for the State of Texas, do hereby certify that this transcript is a true record of the proceedings referenced above, as transcribed to the best of my ability.

I further certify that I am neither attorney nor counsel for, related to, nor employed by any of the parties in these proceedings. Further, I am not a relative or employee of any party in these proceedings, nor do I have a financial interest in this matter.

Subscribed and sworn to on this the 30th day of September, 2001.

Diana Ramos, CSR No. 3133
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