BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

- - - - - - - - - - - - - - - - - - -x
IN THE MATTER OF: : Docket Numbers
PREVENTING UNDUE DISCRIMINATION : RM05-25-000
AND PREFERENCE IN TRANSMISSION : RM05-17-000
SERVICE :
- - - - - - - - - - - - - - - - - - -x

Commission Meeting Room
Federal Energy Regulatory
Commission
888 First Street, NE
Washington, DC
Thursday, October 12, 2006

The above-entitled matter came on for technical, conference pursuant to notice, at 9:07 a.m.

BEFORE: JOSEPH T. KELLIHER, CHAIRMAN

APPEARANCES:

COMMISSIONERS PRESENT:

COMMISSIONER SUEDEEN G. KELLY

COMMISSIONER MARC SPITZER

COMMISSIONER PHILIP MOELLER

COMMISSIONER JON WELLINGHOFF

P R O C E E D I N G S

(9:07 a.m.)

CHAIRMAN KELLIHER: Could I ask that the conversations come to a close, or you could take them out into the hallway? I think that's what they say in Congress.

Let me begin with some brief opening remarks, and then I'll ask my colleagues if they have some comments they want to make, and then we can turn to Staff to describe how the day will be structured, and then we can proceed with the panelists.

Today, the Commission holds a Technical Conference on the subject of Reforming our Open Access Transmission Rules. The purpose of our reform effort is very clear: It's to eliminate any opportunity to engage in undue discrimination or preference in transmission services.

And OATT reform, I have to acknowledge, is a top personal priority of mine, since I've been at the Commission and become Chairman.

Now, based on the initial comments we have received on the NOPR, the reform effort is also perceived as needed, by the industry. The Commission issued the OATT reform NOPR on May 19th of this year, and while not in complete agreement with every aspect of the NOPR, responses to our proposal and to the NOPR, have been largely positive.

And between the initial and the reply comments, we have received 216 comments, totalling over 5,700 pages. So we have a very extensive record to work from.

Now, through extensive outreach efforts, both before the issuance of the NOPR and afterwards, and through review of the comments, we've identified three main areas of OATT reform that we think would benefit from further discussions today.

Those three areas will be the subject of today's technical conference, and they include: Transmission planning, ATC calculation, and redispatch and conditional firm service.

Now, speaking only for myself, I'm convinced that we must provide for strong regional transmission planning, and also act to assure greater consistency and transparency in ATC calculation.

To me, the question is not whether we should act in these areas, but exactly what form our actions should take, and I hope that the Technical Conference will help answer that question.

Now, with respect to redispatch and conditional firm service, I start off with a preference for the NOPR proposal favoring redispatch, however, I also see merit in conditional firm service, and want to explore this option.

Now, in these areas, I acknowledge that I have an open mind, and I look to the quality of the comments and the presentations, and so I encourage the presenters on the third panel, as well as the first and second panels, to be as persuasive as possible.

Now, to allow all interested parties to express their views regarding these topics, we will allow comments to be filed with the Commission regarding the subjects addressed at the Technical Conference today. Such comments, in addition to panel members' prepared materials and transcripts from this Technical Conference, will be available on our E-Library system and our website, www.ferc.gov, on the Calendar Page for this Conference.

And all these materials from the Technical Conference, will help establish a record that will assist the Commission in issuing a Final Rule in this proceeding.

Now, in gratitude for our panelists for helping us today, we'll provide lunch for the panelists to thank them for their participation in the Technical Conference and in our OATT reform efforts.

I particularly want to commend the Staff for their outstanding work on this effort. The performance of the OATT Team has been superb, not only in preparation of the NOPR, but in the outreach efforts, the review of the extensive record, and in the organization of this Technical Conference. I think your work reflects very well on the quality and expertise of the Commission Staff.

I also look forward to hearing the views of the panelists, but first I'd like to ask my colleagues if they have any opening comments they would like to make before we hear from the panelists.

COMMISSIONER KELLY: Thank you, Joe. I wanted to compliment you on your leadership in OATT reform, and, as many of you know, this was an issue that Joe championed, actually, long before he became Chairman, not long after he joined the Commission.

It's very valuable, and it's quite a high-profile effort of the Commission today, thanks to Joe. I just had a few comments to make.

First of all I wanted to thank all of you who are here today. I know that you're very busy, and I appreciate your taking your time to come here and talk to us personally.

There is something that is significantly different about hearing people and seeing each other face-to-face. We read the comments, or we read most of the comments or --

(Laughter.)

COMMISSIONER KELLY: Our Staff reads the comments, and it's great to have all that paper on your desks, but there's nothing like hearing from someone face-to-face.

As I have read the comments and talked to people around the country, the thing that has struck me, is that when Order 888 was passed, the emphasis was on "open" access. And today, it appears to be on open and adequate access, and that's the theme that I hear, and that's also reflected, to an extent, in the topics that we're covering today -- transmission planning, ATC reform, redispatch, and conditional firm.

And part of what we're looking at, is the -- a part of what I'm looking at, is the best way to make full use of our existing transmission grid, as well as looking at ways to expand that grid, and I see that reflected in your comments, as well.

Just one final point: It's been ten years since we issued -- FERC issued Order 888, and it will probably be ten years more before we undertake a big reform effort like this. So I think that really underscores the importance of this endeavor.

What we're looking at, is reforms that will enable us and you to do the job that needs to be done for this country, in having a more robust and open grid in the next ten years. Thank you.

CHAIRMAN KELLIHER: Thank you, thanks for your comments. Colleagues? Mark?

COMMISSIONER SPITZER: Thank you, Mr. Chairman. I, too, want to express appreciation for your efforts.

I first read the document when I was in Arizona, and we had a conversation, and certainly the Chair's efforts on this important task, I think, have borne some fruit immediately, by some consensus being reached.

There are thorny issues that remain, particularly today where we are focusing on a few of them, and we hope to achieve some degree of consensus, and if consensus can't be reached, then with a better understanding of the issues, we can ultimately make an informed and prudent and thoughtful judgment.

I want to take just a moment -- my friend, Jim Kerr, is here, and his status, both within North Carolina and NARUC, is a testament to his public service. And I'm very appreciative, Jim, of your efforts, and will intently listen today.

The issue of open planning, which is our first topic, is one that was very salient in the West, and it's one of those issues where there are benefits beyond those that meet the eye, initially.

We have planning sessions going back to the beginning of my tenure in Arizona, and the degree to which information was broadcast out into the community from these joint meetings, among states, as well as among interested parties, and to those who didn't typically participate in proceedings before the Arizona Commission, made it much easier down the road, to site transmission.

And, again, it's not intuitive, but the open dialogue in the process was very valuable, and I'm hopeful that that type of dialogue and open process today, will also generate benefits. Thank you, Mr. Chairman, for your efforts on this issue.

CHAIRMAN KELLIHER: Thank you. Bill?

COMMISSIONER MOELLER: I'll echo the earlier comments, Mr. Chairman, and praise you for bringing this issue up. This was such a monumental Order, ten years ago, and it goes with my philosophy that when we make major policy decisions at some time in the future, as in now, ten years, we should go back and take a look at what's working, what's not, and make changes. Thank you for doing this.

CHAIRMAN KELLIHER: Thank you. John?

COMMISSIONER WELLINGHOFF: Thank you, Joe. As all my fellow Commissioners commended you, I'd like to commend you, as well. This is a monumental effort, and the more you dig into this NOPR, the more you see its potential import. It has tremendous import overall.

And it fits right into my philosophy, as well, and that is, you know, maximizing and improving the efficiency of the electric infrastructure and its use and operation. I think that's what we're really trying to accomplish here, and it's something that is really near and dear to me, going all the way back to 1983, when I, in Nevada, wrote one of the first Integrated Resource Planning Acts there, so I'm very interested in the planning aspect here, very interested in how -- you know, in 1983, we had, you know, markets that were just barely operating on a wholesale level, and now markets are much more robust.

So, obviously, we need to look beyond just state jurisdictions, as we did at that time in integrated resource planning, and I think this NOPR does do that, and consider how we can do then, ways to be considerate of state jurisdictions' responsibilities, and their interests, as well, and do that in a way that we can do it collaboratively.

So I'm very interested in that. I also want to commend the panel and thank you all for answering the questions with respect to demand response that we put in this particular workshop session.

It is one of the ways, I believe, that we can improve the efficiency of the transmission system and its operation, by integrating demand response in as an equal partner, and I look forward to asking you more questions in more depth about that, as well. Thank you.

CHAIRMAN KELLIHER: Great, thank you. Why don't we turn to Staff now, to explain a little bit about the structure of the Conference, and then we can hear from the panelists.

MR. HEDBERG: Good morning, all. We'll be having an open structure here this morning. Please feel free to exit and reenter today's Conference, as necessary.

Please turn off all your cell phones and pagers. Restrooms are located on either side of the Commission meeting room at the end of the intersecting corridors, by the elevators.

We have a very ambitious agenda for today's Conference, so, panelists, please limit your opening remarks to five minutes. We have a clock provided for you to see how much time you have left, and I'll remind you when you have a minute left to conclude your remarks. Thank you very much.

If time permits, at the end of the day, after the panelists have concluded, we will open the floor to comments for audience members. Thank you very much.

CHAIRMAN KELLIHER: Let's turn to the first panelist, Commissioner James Kerr, and I want to thank you for joining us today and for helping us out. Jim?

MR. KERR: Thank you, Mr. Chairman. I'm Jim Kerr with the North Carolina Commission, and also of NARUC, and so here this morning representing -- wearing several different hats and representing several different perspectives.

The five-minute clock is intimidating to someone from my neck of the woods. We talk slow and think slower, I think, so Mr. Larcamp assures me he'll pull the plug on the clock, if I get in danger.

(Laughter.)

MR. KERR: But I do want to, on behalf of NARUC, officially welcome the three new members of the Commission, and I want to begin my remarks this morning, by speaking more generally beyond the terms of the NOPR, but to speak to the working relationship that we believe exists, and comment on the constructiveness of the working relationship that we are thrilled exists between this federal agency and NARUC and our member states and commissions.

When we look at our relationships with your sister federal agencies, to be quite honest with you, we hold this up as the model for how we ought to interact with our federal colleagues.

We have had cooperative work on resource procurement. We just announced or will announce shortly, a working group on demand response, and, beyond that, just the day-to-day communication.

You know, we recognize that, collectively, we share responsibility and obligations over the provision of what is an essential service to our economy and to the lives of the citizens of the state, and we are appreciative that the working relationship we have, is reflective of the significant shared responsibility that we enjoy.

In this NOPR, we have filed formal comments, reply comments. With respect to today, I have filed a written statement. I should be clear that someone on my behalf, has filed a written statement, as well as written answers to the specific questions.

I want to begin briefly by just letting you know that the written products that we file in these dockets, is the product of an open, collaborative, transparent, working group process within NARUC.

So we believe, as you believe, that such characteristics are important to the production of good work, be it transmission planning or written comments.

We go through -- since the NOI, we have formed ourselves, within the Electricity Committee, into working groups that are representative of different geographic regions, different market structures, different retail delivery structures.

They contain staff, both legal and technical staff, and so the point I want to make is that I do believe the work product that we file with you on not just planning, but on all of these issues, really is a good reflection of, you know, where we unanimously say, for instance, we are strongly supportive of your efforts and planning, you can take that to the bank.

I think there are places where we say to be careful, be cautionary, and you can similarly, I think, trust that that's a place that, collectively, states have put their judgment together and sought to give you their best advice in that regard.

So, I think that in our comments, you will see strong support for the characteristics or the principles of openness, for increased breadth, a broader view of the planning process, transparency, and collaboration.

There is, however, advice, again, grounded in the actual experience of the folks working on these comments, the collective judgment of that group, that in certain areas, the federal regulators should, we think, for good reason, show deference and be restrained from being too prescriptive.

I do want to be clear, though, that the calls for deference are not made in a vacuum, nor are they calls to maintain a status quo, but, rather, they are premised on the belief that there will be processes which are open, collaborative, inclusive. You know, you can run on with the adjectives, but, I mean, where we say to be deferential, we are presuming that there will be the type of planning processes in the regions, to which you have spoken and to which you have indicated an intent to require participation, and so what our view is, is that if you have such a process, then there are legitimate places that that process will decide some of these questions, such as cost allocation, such as the actual definition of "the region," whether or not there's a need for an independent party to be involved.

So it is not to leave it with the transmission owners to do the planning for themselves; it is to create processes, and then there are some issues, once the types of processes that we all agree on, exist, where there are places that you should defer to those processes.

My time is up, and I'm barely getting going, so let me just try to be very quick, and I will not go through the summary of the written comments that we have.

I do want to talk briefly, if I can, about two processes that are ongoing in the Southeast, and then I'll answer whatever questions that you have.

There are two different processes you all -- and we're appreciative that you acknowledged the North Carolina Transmission Collaborative in the NOPR itself. There are a couple of points about these, and I'll briefly describe them.

Each of these efforts predated the NOI or the NOPR. These were efforts that we, in our region, thought were important to begin on our own.

And so this is not in reaction to your thoughts on it, but, in fact, I think they were -- I hope your thoughts were informed, as they were reflected in the NOPR, by what you saw going on, and not just in the Southeast, but certainly in the West and other regions within the RTOs, as well.

In North Carolina, in particular, we have a Transmission Planning Collaborative. You have put Mr. Ingersoll beside me, who deals with this every day, so he can handle the technical. I appreciate your putting him beside me, so he can handle the technical questions, and so I'll defer to him on this.

But let me summarize for you, why we've done what we've done. We found ourselves -- this process was initiated because we understood that there were significant long-term transmission constraints.

The transmission-dependent utilities in our region, were concerned regarding a lack of transparency in transmission planning, and we at the State Commission, with some encouragement from some members of our Congressional Delegation and others who were interested in these issues, we encouraged the parties to jointly address the situation that we found.

Let me tell you briefly where we were and where we are now. Prior to forming this Collaborative, we had separate planning processes for both Duke and Progress.

We had separate models and assumptions; we had limited collaboration or the sharing of ideas; we were purely focused on reliability; we had little input from non-transmission-owning stakeholders, and the OASIS system was the only source of information.

Today, our process in North Carolina, can best be described as having combined planning for both Duke and Progress, combined models and assumptions; the TDUs have access to all information, with equal voting rights for transmission owners, as well as TDUs.

We have third-party oversight of the process; we have a dual focus on both reliability, as well as access to regional resources, and we have a method for participation by all stakeholders.

In about two years, we've gone from, I think, what we all concerned is inadequate, to what we believe is significant improvement, and we've done it with a fairly light hand. To be honest with you, we got them all in a room and told them we thought this was important, and we left them to figure out how to do it, and I think that's supportive of some places where in this NOPR, you're being encouraged to take a light touch.

Let me also briefly comment on a process that's going on in SEARUC, across the ten-state regions. Chairman Hochstetter of the Arkansas Commission, and I, frankly, in conversations with Commissioner Kelliher, I think, before the NOI was produced, had thoughtful discussions of planning.

And I think Sandy and I shared an interest in exploring this further. We, this Summer, dedicated our annual meeting, the electricity portion of our agenda, to two full days of meetings around what we could do -- what we were doing, and what we might do better in the region.

We brought in from the Salt River Project, the representative to WECC who is Rob -- and I can never pronounce his last name, but I think you know -- John will know who I'm talking about.

MR. KERR: And he worked with us, and we brought Rob in because we wanted to avoid the initial reaction that, oh, we can't do this in our region. We wanted someone to come in, who had gone through and fought a lot of these battles, and he's a real resource, and we were appreciative of the Salt River Project making him available to us.

We had broad representation. We had EPSA, we had renewable resources in the room, Rob Gramlich, formerly of the FERC Staff, and we had the transmission owners, the TDUs, and we spent two days.

We came up with kind of a list of principles.

They look much like yours. Somehow, we got to 12 instead of eight, which, as long as I'm going over, you can see we have a tendency maybe to be less brief --

(Laughter.)

MR. KERR: -- than you all, but we circulated that to the group. We have a ListServe. We circulated that. Progress Energy did a detailed critique. We circulated their critique.

We then met this Summer in San Francisco during the NARUC meetings, and argued about Progress's critique, but we, I think, learned a lot from that. We had CAPX 2020 send a representative from the Midwest, to meet with us, and, again, to give us a kind of we've done this, these are the lessons learned approach.

We are in the process of drafting the strawman, and the "we," here, is Chairman Hochstetter and myself, with some help from other folks. We plan, in the next week or so, to circulate it to the group.

I should also say that we have had support from your Staff, senior Staff, here, who have been kept in the loop, and have been available to us to share their thoughts. And what we hope we will do, is come forward at some appropriate time, with a resolution or something in support of a strawman, which would, we hope, serve as a political statement in the Southeast Region, that we, as the state regulators, believe that this is something that should be pursued.

I think, thankfully or conveniently, from our standpoint, you know, your efforts here in this NOPR, will come overtop of that from the federal level, and so that what we would hope would happen, is that we would have kind of a joint federal/state position that, in the Region, we believe that there's value to be gained here.

So, I am six and a half minutes beyond my time and so I will stop there and look forward to your questions. Thank you.

CHAIRMAN KELLIHER: Thank you. I want to thank you for your comments. That was very helpful and worth every minute.

(Laughter.)

CHAIRMAN KELLIHER: But I want to warn the rest of the panelists --

(Laughter.)

CHAIRMAN KELLIHER: -- that you will be held strictly to the time limits.

MR. KERR: The Chairman needs to tell Mr. Ingersoll that he can't have his five minutes.

(Laughter.)

CHAIRMAN KELLIHER: So, now, we'll hear --

MR. KERR: When you have them by the rates, their hearts and minds follow.

(Laughter.)

CHAIRMAN KELLIHER: He was nodding a lot.

(Laughter.)

CHAIRMAN KELLIHER: We'll now hear from Mr. Verne Ingersoll, Director of Regional Planning, System Planning, an Operations Department of Progress Energy. Mr. Ingersoll?

MR. INGERSOLL: Thank you, Chairman Kelliher. Good morning to you and the Commissioners and Staff.

Progress Energy greatly appreciates the opportunity to be on this panel. I, myself, am an engineer, and having to follow up discussions after Jim Kerr, that's a tough route for an engineer to follow, but I'll do my best.

I do want to mention, before I start my regular remarks, that we filed extensive comments in this proceeding, and also the comments of EEI, we think, are very good, and Progress is very supportive of the comments that have been filed by EEI.

Progress Energy is a major transmission service provider, with over 11,000 miles of transmission in Florida, North Carolina, and South Carolina.

We have been providing reliable and economic service to customers for over 100 years, so we've been at this a little while.

Progress Energy strongly supports the NOPR principles of openness, collaboration, and transparency in the transmission planning process, and we strongly encourage the Commission to issue flexible guidelines concerning the development of collaborative and voluntary transmission planning processes that adequately accommodate regional differences.

Based on the experience, Progress Energy has found that voluntary efforts that support collaborative approach to transmission planning, are very beneficial in the planning process. Jim mentioned some of those.

What we've been able to do, working with the load-serving entities in our area, has been very helpful to us, as well as to them.

The Commission, in Section 28.2 of the pro forma OATT, in our opinion, really opened the door for what we're doing in the Carolinas where directed transmission providers, to include network customer load and their transmission system planning, and to endeavor to construct and place in service, sufficient transmission capacity to deliver network customers, network resources to their load on a comparable basis, to the transmission provider's own resources.

You can't do that, if you don't talk to folks. Moreover, the Energy Policy Act of 2005, further strengthened the protection and priority of service for load-serving entities.

In response to these directives, and in an effort, as Jim mentioned, to meet the needs of our network customers, Progress Energy is working to improve the transmission planning processes in the areas in which we operate.

In the Carolinas, we sponsored the establishment of the North Carolina Planning Collaborative, which Jim referred to. It's a little bit of a misnomer, in that the Duke and Progress service territories span a good part of South Carolina, so we really overlap. But it was the folks of the North Carolina Commission who really got us all in the room together and got us going.

But, also, in Florida, we supported the expanded regional transmission planning process there. That is open to stakeholders.

And in CERC, the CERC region, the transmission planning process there, is being enhanced to provide a broader participation of industry stakeholders and greater interregional coordination.

You may or may not know that just recently, the six regional reliability organizations in the Eastern Interconnection, signed a Joint Reliability Coordination Agreement. This Agreement provides a platform for coordinated transmission studies going forward, across the entire Eastern Interconnection.

These processes are providing network customers and other stakeholders, with better information, greater consistency in planning assumptions, and a platform for planning innovation.

I'm a slow speaker, like Jim, so --

(Laughter.)

MR. INGERSOLL: I may have to skip some of this. But on geographic scope, we feel that an effective regional planning process should be of sufficient scale to allow meaningful planning, but not so large as to become cumbersome and inefficient.

In Florida, which is a relatively small region of less than one full state, we have a process that expands the entire region. But CERC is a huge, huge regional council, and to try and do that all in one room, just is not practical.

So variation needs to be allowed, and we feel it would be best to leave this to the participants. They're going to have to pay for it, they're going to have to make it work.

We think they're in the best position to decide what works for them.

On confidentiality, Progress believes that protection of confidential material is critically important, and detailed information cannot be put out in the public domain, in many cases, without jeopardizing national security and grid reliability, and distorting the marketplace.

In addition, LSEs should not have to disclose their competitive information to entities that may be their potential power suppliers.

Through our experience, we've found that a two-tiered approach to stakeholder participation, combined with an appropriate confidentiality agreements, provide for an open and transparent planning process, and, at the same time, protects the confidentiality of information that you need to have to assure compliance with the Standards of Conduct.

On congestion studies, transmission congestion can be analyzed in a large number of ways. There's not just one way to do it.

DOE recently did one economic approach to it, and there are others. For example, in the North Carolina collaborative process, we provide for the study of an LSE's generation resource alternatives and the study of transmission customers' transmission expansion plans or potential plans.

These studies convey the necessary information to the LSEs and to other transmission customers, concerning current and potential future grid congestion. This information can then be used by the individual LSEs or other transmission customers within their own planning processes, to arrive at least-cost resources to meet their needs.

MR. HEDBERG: Mr. Ingersoll, you've exceeded your five minutes. If you could please conclude your remarks?

MR. INGERSOLL: Let me just say that we think a third party can be very useful. We have a third party in our collaborative process, and in some cases regional councils, as they do in Florida, can serve in that role.

But it must be recognized that the transmission planning process is not an end in itself. The true measure of an effective transmission planning process, is the provision of a transmission infrastructure that provides for reliable and economical delivery of electric energy to customers.

We are proud in the Southeast that we have achieved these objectives. The Southeast has a long history of effective regional coordination of transmission plans and in making transmission investments needed to ensure an economic and reliable transmission system that supports the economic growth and well being of the region.

This is an example: From 2001 through 2005, transmission owners in CERC --

CHAIRMAN KELLIHER: I want to reassure you that your statement is incorporated into the record, in full, so, if you could really summarize, I'd appreciate it.

MR. INGERSOLL: I'll just say that -- let me just close then, Mr. Chairman, by saying that over nine years, CERC will have invested -- CERC companies will have invested over $11 billion in the transmission system by 2010, and we think this is the real measure of an effective planning process, getting transmission built. Thank you.

CHAIRMAN KELLIHER: Thank you. Just for the purposes of all of the panelists, your statements are incorporated into the record, in full. We've all seen them in advance, and I think we've reviewed them in advance, so you can really use the time as an opportunity to emphasize or summarize.

With that, Ms. Johnson is the Director of Transmission Asset Management for Excel Energy. We look forward to your comments.

MS. JOHNSON: Thank you, Mr. Chairman and Commissioners. My name is Sandra Johnson, and I am the Director of Transmission Asset Management for Excel Energy Services.

In my position, I oversee transmission planning for the Excel Energy utility operating companies, which own and operate approximately 17,500 miles of transmission facilities in ten states.

We expect to invest nearly a billion dollars in new transmission over the next three years.

I appreciate the opportunity to appear before the Commission today to discuss FERC's proposed OATT reforms on regional transmission planning. My comments today primarily reflect the positions taken by Excel Energy in our initial and reply comments submitted in this docket.

Excel Energy is a member of EEI, and we have generally supported the positions that EEI has taken. On behalf of EEI, I would like to note that EEI supports greater regional and local coordinated transmission planning.

EEI believes that the Commission's proposals to require all utilities to develop coordinated planning proposals, consistent with the NOPR, will, in many instances, serve to formalize the widespread voluntary and regional planning already established in much of the country through RTOs and ISOs, as well as collaborative transmission planning by non-RTO/ISO utilities.

Accordingly, EEI asks the Commission to rcognize and respect local and regional differences in establishing principles for coordinated planning, and to provide sufficient flexibility for the implementation of those principles.

The remainder of my introductory oral comments, reflect the views of Excel Energy. I will address only some of the questions listed in the Technical Conference Notice.

My prepared written statement, which has been submitted for the record, does address all the questions.

My comments today, as well as the positions stated in our initial comments and reply comments, reflect the fundamental characteristics of our service territory.

Excel Energy is one of the few utilities with operations in three distinct regions in both the Eastern and Western Interconnections. Northern States Power Companies operate in the Midwest ISO; Southwestern Public Service Company operates in the Southwest Power Pool; and Public Service Company of Colorado, operates in the Western Electricity Coordinating Council.

Historically, the practices in these three regions, have been quite distinct. Because of these facts, Excel Energy is quite supportive of the Commission's proposed reforms taht improve transparency, reduce ambiguity, and increase the consistency in transmission planning.

Our views also reflect the fact that Excel Energy operating companies, are both transmission owners and significant transmission service users.

In response to the Commission's query on appropriate geographic scope, Excel Energy supports the geographic scope of regional planning consistent with broad areas of interconnected operations like the WECC, Midwest ISO, and SPP.

These geographic areas are large, however, the organizations conducting the regional planning currently have the core system and infrastructure knowledge to conduct the regional plans.

The organizations should be able to implement appropriate mechanisms to meet the Commission's eight proposed guidelines.

Excel Energy believes subregional planning is also critical and should not be subjected to a predetermined geographic scope, such as a multistate or that geography covered under a Section 215 regional entity.

Subregional processes should be given deference to accomodate the needs or requirements of states or parties that participate in such subregional processes.

Subregional processes may be initiated to comply with state regulatory requirements, state resource planning, or transmission planning obligations, reserve-sharing group requirements, or agreement among the parties that participate in such subregional initiatives.

These subregional plans can then be incorporated into larger regional plans.

I would like -- actually, I'm going to skip that one and I'm going to go right to the question regarding demand response.

Excel Energy and its operating companies have played a major role in advancing and relying on demand response and demand-side management, to reduce the need for new generation and associated transmission.

Currently, the Excel Energy utilities have nearly 1400 megawatts of controllable load, and 380 megawatts of --

MR. HEDBERG: Excuse me, Sandra. Please take one minute to conclude your remarks. Thank you.

MS. JOHNSON: Sure.

Just to say, with respect to demand response, our planning studies typically do use load forecasts that account for the impact of demand response programs, evaluating the reliability and integrity of hte transmission grid.

Public utilities with demand-response programs, have and will continue to rely on demand response when forcasting load for the transmission planning process.

Therefore, Excel Energy does not foresee that any change in the OATT is necessary to address demand response in the transmission planning process.

And with that, Excel Energy thanks the Commission and their Staff for their leadership in continuing to improve transparency in regional planning.

CHAIRMAN KELLIHER: Great. Thank you for your statement. And now Mr. Jay Loock, the Dirctor of Technical Services of the Western Electricity Coordinating Council.

MR. LOOCK: Thank you, Mr. Chairman. It's a great honor to be here with you and the Commissioners. We appreciate this opportunity, and, actually, Rob Concioka -- that's how you pronounce his last name --

(Laughter.)

MR. LOOCK: -- asked me to be here. We were hoping he could be here today, but he's asked me to fill in for him, so just briefly -- and I think maybe I can get us caught up on our schedule. I don't think I'm going to take the five minutes, but as you know, WECC is the largest, geographically, adn the most diverse of all the regional councils in NERC.

And WECC has had coordinated regional transmission planning in the West for decades, and supports the Commission's principles for coordinated open and transparent transmission planning.

WECC has traditionally addressed and will continue to address transmission planning from the perspective of reliability of the Western Interconnection.

As the Commission is aware, WECC has expanded its role to encompass new functions related to economic transmission expansion planning.

In addition to revising the bylaws in 2004 to remove language prohibiting the WECC from performing transmission expansion planning studies, WECC has taken on responsibility for managing an economic transmission expansion planning database for the Western Interconnection.

WECC has also recently formed a new policy committee under the WECC Board of Directors, and the name of this Committee is the Transmission Expansion Planning Policy Committee, or TEPPC.

Now, TEPPC's role is to guide and oversee the WECC in responding to the need for regional economic transmission planning and analysis.

WECC is focusing its expansion planning efforts on providing impartial and reliable data, public process leadership, and analytical tools. Of particular importance with respect to the planning objectives the Commission has identified in the NOPR, it is TEPPC's responsibility to ensure that the WECC's economic transmission expansion planning process is impartial, inclusive, transparent, properly executed, and well communicated.

The planning process must, at a minimum, include regional experts and stakeholders such as state and provincial energy offices, regulators, resource and transmission developers, load-serving entities, and environmental and consumer advocates.

TEPPC is also responsible for organizing and coordinating activities with subregional planning processes in the Western Interconnection. And, with that, Mr. Chairman, I conclude my remarks.

CHAIRMAN KELLIHER: Thank you very much. Next, we'll hear from Mr. Peter Wybierala, Director, Transmission Planning, NRG, on behalf of the Electric Power Supply Association. Thank you.

MR. WYBIERALA: First of all, I want to thank the Commission and the Electric Power Supply Association for affording me the opportunity to speak at this Conference today.

NRG Energy owns and operates about 25,000 megawatts of power plants in variuos RTOs, ISOs, PJM, New York, New England, ERCOT, California, and also operates in the State of Louisiana.

In addition, NRG has numerous development and repowering activities going on in each of these states. As such, NRG has a unique perspective of what I would characterize as the good, the bad, and the ugly, when it comes to discrimination and preference in the provision of transmission service.

The specific topics that I'm going to address here today, relate to the overall transmission planning process. This includes such things as model development, study procedures, geographic scope, frequency of conducting studies, types of studies, economic and reliability considerations, transmission congestion, and, finally, the issue of independence.

Under model development, currently, power system modeling by non-RTO IOUs, abounds with opportunities for discrimination. Power system models are supposed to provide at least some semblence of expected real-time operation.

The current models often have inaccurate system topology representation; they lack special protection schemes that transmission owners use for their own needs, and special operating procedures that are in place to mitigate system limits.

Also, the numerous assumptions and judgmental calls that go into these models, particularly as it relates to load representation and generation dispatches, is problematic.

Typically, the transmission owner has many generators throughout the system that can redispatch at will to impact transmission availability over congested paths. Likewise, the same is true for load forecasts.

The change in the assumption on peak temperature, has a direct impact on system load, which, again, directly affects transmission availability.

System line and transformer ratings are another problem. Short-term ratings, in many instances, are not available in the planning models, but are relied upon for the real-time operation of the system.

These are just some examples of how a transmission owner can manipulate the system models to discriminate against other market participants in favor of its own interests.

The next issue I would like to talk about, is NERC versus the -- the NERC planning models, versus the OATT models.

A new approach that I have recently seen to disrcriminate, is to exploit the opportunity to post OATT system models on the OASIS, that are different from the transmission owners' representation and the regional NERC planning models that ultimately become incorporated into the Multiregional Modeling Working Group, also known as MMWG.

The process goes something like this: The transmission owner adopts a budget horizon, let's say, of three years, that's less than the five-year horizon required by NERC.

The NERC models are supposed to have planned system upgrades through, say, the five-year period. The transmission owner conveniently leaves out the planned system upgrades for years four and five from the OATT models, on the basis that the upgrades are not officially budgeted, and, therefore, it would be improper to sell transmission service predicated on these upgrades.

This, in turn, causes base-case overloads in the OATT models, which severely limits the availability of transmission service, creates barriers to competition to other market participants, without making substantial and often cost-prohibitive system upgrades.

This is cleary discriminatory and prejudicial, and it unfairly shifts the cost of planned system upgrades to other market participants or indirectly affects denial of service.

Requiring transmission owners to post OATT system models that are consistent with the NERC models, would solve this issue.

System studies: System studies should be conducted at least annually and in a manner that addresses the economic aspects of system expansion, in addition to reliability.

It's not sufficient to only model a system snapshot of the forecast peak load hour. NERC transmission planning, N minus one criteria, under Note B, does not require resolution of all base-case overloads by allowing planned or controlled interruption of electric supply.

This can be exploited as a convenient way out to avoid upgrading the system and leading to discrimination. Hourly transmission constraint production costing -- quantify the cost of redispatch --

MR. HEDBERG: Excuse me, but please take one minute to conclude your remarks.

MR. WYBIERALA: -- and unserved energy also needs to be conducted to ensure that the transmission system has expanded in a reliable and economic manner.

In general, base case overloads that cannot be resolved through redispatch, should not exist in any system model, unless it can be demonstrated that it's not economical to upgrade the limiting facility, based on the duration and risk of the load.

Transmission congestion and redispatch: Another form of discrimination is the preclusion of market participants from access to redispatch of the transmission system owner's own generation.

Transmission availability and generation go hand-in-hand. One cannot be evaluated, without considering the other.

Operation requires the optimization of generation and transmission over all projected load levels and operational conditions.

Furthermore, market participants causing transmission congestion in day-ahead or real-time, need to pay equitably for the congestion that they cause, and with that, I think I'll conclude my remarks, thank you.

CHAIRMAN KELLIHER: Thank you. I'd like to now recognize Michael Kormos, the Senior Vice President of Reliability Services, PJM Interconnection.

MR. KORMOS: Thank you, Commissioner, and thanks for the opportunity to come down and talk about it.

I have provided written comments and answered the eight questions explicitly, and what I really would like to take the five minutes to do, is to discuss some of the lessons learned, that PJM has experienced in our regional planning process.

As you know, we've been doing regional planning for about ten decades -- or, for about a decade, ten years --

(Laughter.)

MR. KORMOS: It feels like ten decades, sometimes.

(Laughter.)

MR. KORMOS: We have learned a lot during that time, and we've made a lot of changes, and we're actually in the process of making even more changes as we speak.

I think that throughout that time, though, our goals have been very consistent with what the Commission has before it. We look at our process as being -- wanting to be open, to be inclusive, and ultimately to ensure that the development of the actual necessary infrastructure is done.

In order to do this, we've looke at a couple of outcomes that we believe define success.

The first is having transparent processes, but I would offer that transparent processes are not simply putting a plan out at the end and having people look at the plan.

I think they have to be involved in lookig at the assumptions, looking at the criteria, understanding how the studies will be done, understanding how the solutions will be developed, and, then, ultimately, how the plan will be approved, and that will truly show a transparent process.

I also think there needs to be sufficient information coming out of the plan, not only to allow the participants to offer their own solutions and to participate in that part of it, but to make their own business decisions.

I think worked very hard to try to get the information out in front, so whether it's generation developers, demand-side developers, they have the information to make their own business decisions in the future years.

Obviously, all parties need to have the ability to provide input, and, again, I would offer that that input should be throughout the planning process, from the very beginning when the assumptions are developed, to ultimately when solutions are provided.

The last is that I also think it needs to be flexible. We have had some experience, and when we initially started, our main challenge was interconnecting large amounts of generation within a very short time period.

The type of processes we put in place and the types of analysis we did, I think, accomodated it very well, but as the system has moved on, as the industry has changed and we now face the need for additional backbone facilities, we find ourselves really needing to change those processes to look at different kinds of analysis. And I think that that kind of flexibility is important.

I would like to share a couple of reasons why I think PJM has been successful in developing the plan and making these changes: The first is size. I do believe size does matter.

I think bigger is better, but, really, from the fact that you have more alternatives, you have more ability to look at solutions over a larger geographic area.

We have multiple occurrences where we have made enhancements in one transmission owner's system, to relieve problems in a neighboring system's overloads, so I think that's very important, and I think we should really look at that.

I do believe we do need to respect historic flows and natural market boundaries that occur.

I would also encourage coordination with neighboring entities be mandated. I think that kind of coordination also can give you the regional size that may be needed, by making that effective.

Independence is another item that I think has been something successful. I think issues with confidential data, are definitely relieved with independnce. We are able to take a lot of confidential data that we have, put it through our planning analysis, put it in our planning models, ultimately put out aggregate results that don't actualy release any of that confidential information.

Independence has also allowed us to try to balance short-term needs with long-term needs, and I think that throughout the planning process, you're always caught having to make those kinds of evaluations, and I think that the independence helps in that area.

I would also hope that at the end of the day, an independent process that is inclusive, will actually carry some weight at the state commissions in the siting process, as well.

MR. GESCHWIND: I believe we're on the right track by mandating joint regional planning through the tariff. We think that the right direction to go. We do strongly believe, however, that the process needs to be both collaborative and interactive. Joint planning means more than just having the transmission owner, transmission provider tell the participants on the system of their plan. It needs to be a collaborative process. We also believe that RTOs and those transmission owners in those RTOs should not have a free pass from participating in that open and collaborative process.

I'll stop there and look forward to talking more in the question period.

CHAIRMAN KELLIHER: Thank you, Mr. Geschwind.

Our last panelist on this panel is Mr. Will Kaul, Vice President for Transmission for Transmission for Great River Energy. Thank you.

MR. GESCHWIND: Thank you, Mr. Chairman and Commissioners for the opportunity to be here today.

I'm going to take a little bit different approach than going through the questions and talk a little bit about CAPX. It's been mentioned a couple of times. I'm the chairman of that collaboration and I thought it might be beneficial for some of the questions and issues before the Commission to see what we're doing and what has made that effort successful.

Two and a half years ago utilities in Minnesota, several of us, got together and we anticipated the need to make some major investments, both in generation and transmission. Now we asked our planners to look out 15 years and give us some kind of a vision of what the challenge was, and what we saw was 6300 megawatts of load growth and about 8500 megawatts of new generation necessary to meet that load growth. So we went about a process of trying to determine what transmission was necessary to meet those needs.

The group originally started with four utilities. We now have 11 utilities. I think it's significant that they're all vertically integrated utilities. We have investor-owned utilities. We have cooperative GNTs and we have municipal associations and so we have all of the different kinds of utilities. We have many different utilities serving us in Minnesota. So we got together and we're at a point now with our first group of projects. We call it Project Group One -- very original thinking there -- and it's 600 miles of 345 kV lines. It's about $1.3 million of investment and all these projects are fully subscribed by the participating utilities. In other words, we have the willingness to invest in this expansion. The Certificate of Need application to the State of Minnesota is going to be filed in the next couple of months and so we're on our way.

What I wanted to do is just touch on four things that I think are important in making this work and starting with our basic motivation as electric utilities we have an obligation to serve and I think that's probably what got us all together knowing that we needed to make these investments. We also needed to do the planning for our own due diligence as investors and owners and operators in the system so that as you look at requirements for regional planning I would hope that you would consider that basic utility load-serving planning as the building block in any regional transmission plan process.

The second point I want to make is that for us, if you're talking about geography, economic, political and historical factors were important in describing the geography of our plans. Minnesota happens to be the local economic engine in the region that we live in and we had high population growth, high economic growth and also the development of renewable energy resources. All those things were drivers for us in doing this expansion and so that helped describe our planning region. That's where the growth was. That's where the transmission additions needed to be.

We also had political factors and the political factor I'm talking about here happens to be the political boundaries of Minnesota. We're in jurisdiction. Most of the regulatory activity is going to happen there. That also helped describe our planning region, although it does spill out into the neighboring states a little bit, but primarily it's a Minnesota focus.

Then historical factors -- and there are several here that come into play, but one is that the Minnesota utilities that are involved in this have actually been involved in joint planning for a long time, originally through the map area and more recently as fellow MISO members and as integrated utilities. Great River Energy, for example has about 5000 miles of transmission, but we don't have a system. They're a bunch of pieces and that's because we're integrated with all our neighboring utilities. So we have a history of joint planning, many interconnection agreements, joint rate zones, et cetera.

Two other points quickly -- integration and reconciliation of expansion plans within multiple planning spheres was absolutely necessary. Most of us are MISO members. MISO is looking at our plan and integrating it into a larger regional plan. It's critically important. It's also class by our project for purposes of revenue recovery. That was what broke the log jam, frankly, for all of us utilities to decide it was okay to invest because of

RECE. So that was very important.

We also participate in the state planning process. That's also extremely important because the state decides need and sighting and rate recovery. So bringing those three spheres together was critically important.

Finally, last point and I'll get it real quickly, regulatory certainty is the foundation for investment. It's not new news, but we approached it a little bit differently. We decided that regulatory reform should start at home. We went to the state legislature. We got formula rates for the investor-owned utilities. We got a streamline routing process and we got the ability to form a TRANSCO if it's deemed in the public interest. So things have all come together and made this effort successful. Thank you.

CHAIRMAN KELLIHER: Thank you, Mr. Kaul.

Now we come to questions and have to say I have a few questions, but I thought I'd refrain in favor of my colleagues to begin with. I have to say I'm probably more curious about the questions my new colleagues would ask than the answer to some of my questions.

(Laughter.)

CHAIRMAN KELLIHER: But it's something Suedeen and I have been working on for about a year and a half, and I guess this the first opportunity for the new commissioners to really engage in these issues.

I don't want to build up the anticipation for your questions too high, but I'm curious about them.

(Laughter.)

CHAIRMAN KELLIHER: I also wanted to make sure staff knew feel free to ask questions of your own. Don't want until we exhaust every question that comes to mind because I have to hazard that you're probably more familiar with the 5700 pages of record than we are and that we need the benefit of your knowledge. I also want to warn the panelist that Commissioner Wellinghoff is very skilled at cross-examination. So if he's really slicing into you, don't take it personally. Just realize it's instinct or habit for him.

So with that, do any of my colleagues have questions or staff?

COMMISSIONER WELLINGHOFF: Thank you, Mr. Chairman. I hope I can live up to that reputation, although that is my background is cross-examination. So if I get a little bit too edgy here, please back me off.

Let me start off with a few softballs for the entire panel. Anybody can take these and my questions are going to focus on Demand Response issue primarily, although I do have some more specific questions for specific panel members about the planning process, the regional planning processes that you may now be engaged in. I'm interested in exploring that some as well, but let me just start with some general questions on Demand Response.

Can anybody give me their experience with Demand Response as providing support to the transmission system through reserves or other ancillary services? Does anybody have experience with that?

MR. KORMOS: We have recently within the last year filed to allow Demand Response and provide both Spinning Reserves as well as regulation. We have had some Demand Responders actually provide the Spinning Reserve product and yet we have not had anybody on the regulation side.

COMMISSIONER WELLINGHOFF: Let me follow up on that with you, Mr. Kormos. Do you think that Demand Response can provide support to the transmission system through reserves or ancillary services?

MR. KORMOS: Absolutely.

COMMISSIONER WELLINGHOFF: Anybody else want to comment on that question?

Yes, Mr. Ingersoll.

MR. INGERSOLL: We have pretty extensive experience with Demand Response in the Carolinas and in Florida, and we do have procedures in place to allow interruptible loads that can be interrupted by the operator to act as Spinning Reserve or Reserve. Let's just call it

Reserve, Operating Reserve and it can be effective depending on the cost structure. Combustion turbines are not all that expensive, so sometimes they're less expensive than Demand Response. It depends.

As far as transmission, I think the DSM can be or can reduce the load that you plan the transmission to serve but caution has to be used and I've seen that differently in different areas. If the operator doesn't have control over the DSM or if there's no effective way to test what's out there, it somewhat problematic to incorporate it.

COMMISSIONER WELLINGHOFF: So then to the extent that DSM would be used for transmission planning, you would recommend that there would have to be some assurance of operator control?

MR. INGERSOLL: If you're going to rely on it to build less transmission, you have to be sure that it can be operated when it's needed and that can be contractual as well as physical.

COMMISSIONER WELLINGHOFF: Would you also recommend that there be fair value paid for that demand response if it was operator-controlled?

MR. INGERSOLL: Certainly.

COMMISSIONER WELLINGHOFF: Another general question on Demand Response. Does anybody see any barriers to Demand Response other than what we talked about the operator control issues? Are there any other barriers to it providing support for the transmission system under the OATT?

Mr. Kaul?

MR. KAUL: I'd just speak to our experience. In our region we have a lot of Demand Response programs in place and they're not dispatchable, which is important if you want to plan for transmission needs, but one of the barriers you might see is customer resistance. Because we have a lot of Demand Response programs in place, people are getting shut off already for various reasons because they've entered into contractual arrangements. But these periods of getting reduced are getting longer and longer each day and so you might get some customer resistance to that.

COMMISSIONER WELLINGHOFF: I would imagine, Mr. Kaul, that would depend upon the specific type of Demand Response to extent that that Demand Response is, in fact, the interruption of a system or process that's going to be less tolerable by a customer.

MR. KAUL: Absolutely.

COMMISSIONER WELLINGHOFF: One final overall question Demand Response. Does anybody see what options there are for coordinating regions with different approaches to real time economic dispatch? Does Demand Response play a role in that?

Mr. Kormos is reaching for his mike.

MR. KORMOS: Obviously, I believe Demand Response can play a role in real time economic dispatch. We allowed Demand Response to actually put bids into the system. Those bids came, in fact, at the marginal clearing price in the region. I would see no reason why they shouldn't. I absolutely believe they can and we're doing it today.

COMMISSIONER WELLINGHOFF: Thank you.

Some of the more specific questions I have, starting with Ms. Johnson.

Ms. Johnson, in your prepared testimony and I believe in your remarks as well -- your remarks this morning because you addressed to me on response -- you indicated that Xcel did not foresee any needed changes to the OATT necessary to address Demand Response. Is that correct?

MS. JOHNSON: Correct.

COMMISSIONER WELLINGHOFF: You talked a little bit about Xcel's evaluation to Demand Response in your planning process. Could you tell me do you, in fact, evaluate Demand Response to determine if accelerated Demand Response can defer or delay transmission construction when you do planning?

MS. JOHNSON: When we do our planning and we look at our overall resource requirements, we take into consideration any Demand Response. So if it is, in fact, shaving off the peak load requirement, then we are, in essence, not building transmission to accommodate that.

COMMISSIONER WELLINGHOFF: Right. But do you do sensitivity to determine --

MS. JOHNSON: Yes.

COMMISSIONER WELLINGHOFF: You do with respect to expanding Demand Response and how that may affect your transmission needs?

MS. JOHNSON: Yes, we do.

COMMISSIONER WELLINGHOFF: Would that be something you would think would be appropriate to specific in regional planning?

MS. JOHNSON: I don't believe it would necessarily would be required to be so specific about it. I think most planning studies take into account various sensitivities, which include an increase in overall demand. So if it's a 10 percent increase or a 15 percent increase, looking at the various sensitivities to a forecast at peak load I think, in essence, already provides that.

COMMISSIONER WELLINGHOFF: Would you have any objection to including that in the OATT?

MS. JOHNSON: No.

COMMISSIONER WELLINGHOFF: Thank you.

MR. DeJESUS: I wanted to jump in on this and I think it's an echoing of what Mr. Kaul had said. We've had on our distribution side pilot programs to defer upgrades in order to -- based on Demand Response and the issue that we've seen is not so much that customers don't want to be interrupted, but that you don't have enough interruptible load in places where you need to interact those kind of programs to do that. So we do what we can. We find places in the system that require upgrades and see what interruptible loads are out there. We do it by contract. But in terms of an ongoing obligation to do that on a wide scale, I think the problem is finding a group of loads that are -- customers that are willing to be interrupted at the right times to accommodate the deferrals.

COMMISSIONER WELLINGHOFF: Might it also be a problem of providing the right economic signals in the market so such customers can aggregate themselves and businesses can develop business plans, in essence, to develop those kinds of resource?

MR. DeJESUS: Certainly.

COMMISSIONER WELLINGHOFF: Actually, I did have a question for you, Mr. deJesus.

Since you answered one, let me go to that. When you talked about the planning process having a broad look, I assume then you would include efficiency, in essence. Efficiency you list as one of the primary things, which is one of the things that I'm interested in. So I'm obviously, with respect to that efficiency, you would include Demand Response in that subset as well.

MR. DeJESUS: Certainly. I mean we look at all impacts on the system in order to determine what more is needed and that would include Demand Response.

COMMISSIONER WELLINGHOFF: But from your perspective, you're a transmission owner/operator, so you don't really have any way to effect increasing Demand Response, per say.

MR. DeJESUS: We do what we can. We participate in the ISO programs that we belong to and on the distribution side with our contact with retail customers. We do go out and look for opportunities to exploit Demand Response. Exploit is probably not the right word.

COMMISSIONER WELLINGHOFF: Thank you.

The next set of questions for Mr. Loock. Is that how you pronounce your name, Loock?

I was interested in your map you had of your western interconnect of subregional planning groups. It looks like either nobody wanted Nevada or everybody wanted Nevada.

(Laughter.)

COMMISSIONER WELLINGHOFF: They way it's structured you've got how many groups overlapping southern Nevada or is there really any overlap? Or is it just poorly drawn?

MR. LOOCK: It's just poorly drawn. Yes, NTAC is really over that area. Nevada has so much going on there, especially in the Vegas area with generation. But for the most part NTAC does have a little bit interest there and so does SQAP, but mainly I would have to say between SQAP and TAPs.

COMMISSIONER WELLINGHOFF: I was interested, again, in your pre-filed material. Your transmission expansion policy planning committee. How is that committee constituted? Who is on the committee?

MR. LOOCK: There's 17 people on that committee. We try to reach out to all stakeholders to be on that committee. It would be environmentalists, regulators, different people throughout the West that we feel like could have -- and also the chair of each one of those subregions that you see on your map are a part of that TPSI Committee. And the idea is to increase communication between the subregions. If there's policies that need to be developed between these subregions, that's the forum we can do it in.

We have a monthly conference call between these subregional planning groups so they can learn from each other what's going good. What is not going so good. So we feel like, also, that we develop a transmission database that these subregional groups can also take advantage of that and the models that are in there.

COMMISSIONER WELLINGHOFF: Again, I'm just trying to understand. So the Committee is it just WEC board members or does it stem beyond WEC board members?

MR. LOOCK: That's a good question. The Committee itself, the TPSI Committee is just WEC members. However, there's a technical advisory subcommittee that reports to that committee that are WEC and non-WEC members. We've invited and have done an outreach for everyone, whether they belong to WEC or not to participate in that technical advisory subcommittee and from there we've developed work groups -- data collection work groups, modeling work groups, studies work groups, which also include WEC and non-WEC stakeholders.

COMMISSIONER WELLINGHOFF: But the Transmission Committee is -- would you say it is representative of your subregional planning groups?

MR. LOOCK: That's correct, yes. Just repeat that we do have the chairs of each one of those subregional planning groups on the TPSI Committee.

COMMISSIONER WELLINGHOFF: In the second page of your statement, you indicated that WEC recommends that congestion studies be based on cost production modeling to be performed in the western interconnect on region-wide basis every two years. Can you explain for me how that production cost modeling accounts for Demand Response or if it does?

MR. LOOCK: It can. I think in the database we're putting together that we would include that information in there and the reason why every two years is we felt like due to resources that every two years we could have, perhaps, a better model.

COMMISSIONER WELLINGHOFF: Let me go back. Does it, in fact, include Demand Response when you do this modeling?

MR. LOOCK: That's our plan, yes. As we put this database together that is our plan is to include that.

COMMISSIONER WELLINGHOFF: Overall then, what do you see as the role for Demand Response in transmission planning?

MR. LOOCK: That's a good question. Overall, I think there's a lot of programs out there. Programs which I feel like the load-serving entity that has dispatch control are comparable to like other resources. So I think it does have and long-term planning does have a position. But I think without dispatch control it's pretty hard to plan for.

COMMISSIONER WELLINGHOFF: I'm sorry. Without dispatch control?

MR. LOOCK: Without dispatch controls, they're pretty hard to plan for -- long-term planning.

COMMISSIONER WELLINGHOFF: So you also would recommend that there be dispatch controls?

MR. LOOCK: Yes.

COMMISSIONER WELLINGHOFF: Do you know if there are any such programs in the WEC?

MR. LOOCK: I don't know of all the programs in WEC. I can assume there are some. I know the State of California they very aggressively looking to implement some plans.

COMMISSIONER WELLINGHOFF: Thank you.

Mr. Kormos, a few questions on your prepared filed testimony. On page 4, in the middle of the page, you talk about your backbone projects and indicate that the near term estimated benefits from those projects to reduce congestion is between 200 and 300 million a year. Is that correct?

MR. KORMOS: Yes, sir.

COMMISSIONER WELLINGHOFF: Is it also correct that this summer that AGM instituted Demand Response for one week in August and determined that benefits were $650 million?

MR. KORMOS: Yes, sir.

COMMISSIONER WELLINGHOFF: So from that, it just looked like Demand Response may have the ability to, in fact, exceed benefits of backbone transmission, in essence.

MR. KORMOS: I think one of the hardest things here is being able to curtail the load at the very highest priced hours. Obviously, you can see the implications. Some of this congestion, though, unfortunately is probably more spread throughout the year when prices are not quite as high, but still there.

COMMISSIONER WELLINGHOFF: Did you look at, in your modeling and planning, and considerations, whether or not any of this transmission could have been deferred or delayed through Demand Response?

MR. KORMOS: Yes, sir. We actually include contractually obligated Demand Response is already included in the planning process, plus density capacity credit as well as defer reliability requirement is already -- we also do it in the economic analysis. We also do look at the voluntary Demand Response that we have on there and that affect. We have just recently started publishing as well the amount of Demand Response that would be required to remove a particular congestion issue. We do it for generation and Demand Response.

COMMISSIONER WELLINGHOFF: Tell me more about that. That I wasn't aware of.

MR. KORMOS: As part of our economic efficiency, and again, it's now filed with Commission. But we are looking at -- actually, we have actually implemented, although it hasn't been approved, publishing that kind of information so people have to understand what the problem is that they're seeing and the amount of generation that would be needed, located in the areas that it help resolve the congestion.

COMMISSIONER WELLINGHOFF: So you have that available to anyone to look at to determine if you put so much Demand Response in such an area it would reduce congestion in this area and perhaps defer delay of generation transmission.

MR. KORMOS: Yes, sir.

COMMISSIONER WELLINGHOFF: Is that available on your website?

MR. KORMOS: It's on our Transmission Advisory Expansion Committee, which is on our website?

COMMISSIONER WELLINGHOFF: Thank you.

COMMISSIONER KELLY: I have a follow-up question. Is there a dollar amount associated with that? Do you value it as well?

MR. KORMOS: We have not completed the economic analysis piece of it. That's actually what's in front of the Commission now and we're starting those studies. Right now we put it out at a quantity amount. How much megawatts of Demand Response would be needed. The economic efficiencies, though, there are sensitivities that we'll look at to sensitivities and the changes in congestion based on Demand Response being one of the sensitivities we'll looked at.

COMMISSIONER KELLY: When you try to value it, what will you use? Is LMP important in that?

MR. KORMOS: For us, it's absolutely important.

COMMISSIONER WELLINGHOFF: Mr. Kormos, following up on a couple of other things I've got. With respect to your discussion on page 13 of your direct testimony that discusses how critical it is to incorporate and enable states to share information with respect to planning, and you discussed earlier in your testimony your TAC Committee. How does that committee interface with state jurisdictions and how do they do, in fact, what you're recommending and that is incorporate state interest?

MR. KORMOS: That is the process again where we put out information and one of the things we're doing working throughout is making sure that the information that is being made available through that process, throughout the planning process is what the states needs ultimately to make their decisions. So we've encouraged them. For the most part, all the states are active participants in the Transmission Advisory Expansion Council providing their input as well as receiving the information and we believe that will ultimately be helpful in getting the transmission sited if it needs to be.

COMMISSIONER WELLINGHOFF: Just so I understand it then, so there are members of OPSI that are members of TAC. Is that correct?

MR. KORMOS: Yes, the Transmission Advisory is actually an open meeting. Everybody is invited.

COMMISSIONER WELLINGHOFF: I see.

MR. KORMOS: Actually, the FERC staff has come to our Transmission Advisory meetings.

COMMISSIONER WELLINGHOFF: So it's not a selected committee?

MR. KORMOS: No, sir. They are wide open meetings. All the information is public beforehand and then comments are -- we actually now provide the opportunity for all parties to provide us written comments after the meetings. Those comments are then shared with our independent board regarding the issues that have been brought up.

COMMISSIONER WELLINGHOFF: I appreciate that clarification. Thank you.

Now going to pages 18 and 19, your specific answer to our Demand Response question, and I certainly appreciate your comments there regarding your indication that you believe Demand Response resources have the potential impact planning outcomes significantly and I certainly would agree. And that you do believe it plays an important role in the regional planning process. I'd like to explore a little bit on the next page, 19, some of your specific concerns, however, regarding Demand Response.

You indicate that to, in fact, rely on it in planning that it may be necessary to have potentially large liquidated damages provisions. Could you explain that a little bit?

MR. KORMOS: We do not have any operational control and so in most parts all of the Demand Response that we would look for to solve a reliability issue would be contractual obligations. And one of the issues that we have right now is even our contractual obligations are only year-to-year. So while somebody may have agreed to do it this year, they can opt out in the following year. There is no contractual obligation for them to stay in for the long term.

If you're using that to plan and defer a reliability upgrade five years in the future, one of the biggest things we've seen is also congestion is just a precursor to a reliability problem. So typically, if you're going to see a reliability problem, you'll see a lot of congestion beforehand. You also may then exercise Demand Response a lot. We've had experience in the past that when you've done that, they then choose to no longer participate.

The economics just are not there for them any more, whatever business case they developed. So I think that's what we're trying to weigh is how do then do we count on and ensure for reliability perspective -- I think economics you have a lot more flexibility, but from a reliability perspective when you're looking at things that may have very long lead time to get constructed. For us the backbone facilities are maybe 8 to 12 years to get something built and how much certainty and what do we need to put that kind of certainty in place that we know that we can, in fact, count on the Demand Response being there. So obviously, we're not manually creating Demand Response in the future.

COMMISSIONER WELLINGHOFF: So you're saying you need a utility quality resource, in essence, to rely on for planning purposes.

MR. KORMOS: Yes.

COMMISSIONER WELLINGHOFF: Could you set up a list of parameters for the Demand Response industry to tell them what you need to make sure that, in fact, they could be used for reliability planning purposes?

MR. KORMOS: No. And I think that's one of the things we're working through with some of our mini-groups that we have as to look at how we put those kinds of parameters in place such that that certainty exist in the future.

COMMISSIONER WELLINGHOFF: If those parameters were in place, would you then need these kind of liquidated damages provisions?

MR. KORMOS: Probably not.

COMMISSIONER WELLINGHOFF: Because you don't use liquidated damages now for your generators I assume?

MR. KORMOS: In some cases we do. I mean there are certain penalties that generators can, in fact, incur if they don't perform. But I mean I wouldn't consider them extreme.

COMMISSIONER WELLINGHOFF: You talk about having these contracts in place and so forth and these parameters. Do you offer today any such type of product to the Demand Response industry?

MR. KORMOS: Yes. We have an ELM Program, which again requires that they interrupt at least 10 times at our request. There are penalties in place if they do not interrupt during those times. It is a measured reduction. They receive a capacity credit for that against their obligation so that there's a financial ramification for them, a positive one.

COMMISSIONER WELLINGHOFF: Do you see that product as sort of essential mix of products that you think is important with respect to transmission planning overall?

MR. KORMOS: I think that product, from the reliability perspective, is essential because that is what gives us some certainty and we have history with that that they're there. But at the same time we have a large number of voluntary products that we do, in fact, get very good response from, as Ms. Summers said. That is going into the economic planning and I think the real big issue -- and it's not just with demand side -- we have it on the generation side is really when you're looking out 15 years what assumptions should we be making? We have the same issues on generation. We have no control over generation deciding to retire or new generation siting. So how we look at the mix between generation and demand side I think they share a very common problem.

COMMISSIONER WELLINGHOFF: Certainly, generation could decide its uneconomic for release.

MR. KORMOS: Yes.

COMMISSIONER WELLINGHOFF: I'd like to go to Mr. Kaul.

Your written statement that you submitted, the very last page of that talks about the impact of DSM on planning. In your very last sentence there you say, "Unless DM programs are dispatchable for transmission purposes, planners must assume they are building for system peaks." I wasn't quite clear, if you could explain that for me.

MR. KAUL: I think it's basically what we've been hearing here today, which is if you can't control that load for transmission purposes, then you have to assume that you have to build to serve the peaks.

COMMISSIONER WELLINGHOFF: Thank you.

Mr. Chairman, I have no further questions at this time. Thank you.

CHAIRMAN KELLIHER: Thank you, Commissioner Wellinghoff, gentlemen, lady.

Marc?

COMMISSIONER SPITZER: I'm interested in joint ownership of transmission having seen first-hand some successes. I know a lot of parties opined on the jurisdictional issue and the flash point is the mandatory versus voluntary aspects. We have the benefit of having some engineers on this panel as opposed to lawyers, which is wonderful. So having read and certainly feel free to comment on the jurisdictional issue, but with regard to economic or engineering or structural impediments to or arguments in support of, I'd like to hear from the whole panel on the concept of joint ownership and the mandatory nature of that undertaking.

MR. DeJESUS: I know you're asking for engineers and I'm the lawyer on the panel.

(Laughter.)

COMMISSIONER SPITZER: You could

practice engineering without a license and the engineers can feel free to practice law.

(Laughter.)

MR. DeJESUS: We've had great success with joint ownership program on a voluntary basis. One of the big issues that you're going to have to deal with is that the country really needs infrastructure and right away. These joint ownership arrangements take a long time to negotiate. We've got a facility that interconnects New England with Quebec that took several years just in the contracting stage and then you had to get to the studying of the facility and the impact on New England and over the life of a contract there's also the issue of commitment. You have a contract, but when the economics of the deal change -- and they will over time -- various parties will want to renegotiate and that's fine if it were just a pure economic transaction, but these facilities become part of the system and it's hard to just shut down a project when the joint ownership arrangement is done. So I think those are some of the considerations you need to think about when you start mandating joint ownership is that it's real delay and potential for deals to unwind.

The last thing I wanted to note is that one of the things that National Grid has been arguing is that the transmission grid in the United States is very fragmented --

over 400 transmission-owning entities -- and that impacts planning because now you have to create these government structures that allow us to all get in the same room. You don't have the efficient ability to make asset investment decisions while you're planning the system. Joint ownership arrangements, especially if they're mandatory would perpetuate that fragmentation because now you're talking about ownership arrangements on a project-by-project basis, not looking at the system as a whole. So don't get me wrong. We support joint ownership when it makes sense, but a mandate would be a step back from where we're trying to head, especially under EPAC.

MR. GESCHWIND: From a TDU perspective, we strongly support the concept of joint ownership and believe that the users of the system should have the opportunity to invest in the system and graduate away from renter status to owner status through this opportunity to invest. We've had some, I think, success in our region with joint ownership. My company owns approximately $100 million worth of transmission facilities. Again, even though I think we look a lot like a TDU, we've had the benefit of agreements that have allowed us to invest with our transmission provider in the facilities of the region and not unlike Great River Energy, you can't point to the SEMPA transmission system that's represented by that $100 million investment. It's scattered pieces of investment located among four or five different transmission systems.

One of the ways that we benefitted from that is through facilities credits that we have been able to receive in recognition for those investments. Unfortunately, within the TAPs ranks there's probably lots of stories of utilities that would like to become owners in the system and have been frustrated in their efforts to achieve that. In the CAPX process that we're still going through and we talk a lot about CAPX as if it's a raging success. I think so far so good, but we're not done yet. The process there allowed all of the participants in the overall CAPX effort to bring to the table, and we literally had a meeting where we sat down and we had identified $1.3 billion worth of transmission projects that were on this Group One list and we sat down and said here's what I'm in for. Here's what I'm in for and we looked at which projects were subscribed and which were not. There were some shuffling and back room discussions and we ultimately ended up with these projects that were fully subscribed from a capital investment perspective and fortunately that ownership opportunity went beyond just investing utilities and went all the way down to individual municipal utilities.

In order for us to get to that point, though, one of the keys was that we had worked through or at least we think we have a good handle on how the cost recovery portion of that -- I think the willingness of at least my company and others to step up and say we will invest X millions of dollars in the system part of that or a large part of that was due, in fact, to the MISO Attachment O and the RECV process. In that particular case, having this regional cost allocation and the ability to spread the cost for large projects beyond an individual system or an individual system and its neighbor I think was key to breaking the stalemate that Will Kaul mentioned that we were starting to see within our CAPX process.

And if it's not, I think for systems that don't have access to ITOs or the MISO Attachment O or other processes, I think that there are some other reforms that the TAPs has proposed to Section 30.9 of the tariff that I think go a long way towards recognizing fairly the value of investments in infrastructure that all of the parties bring to the network, not just the network provider.

COMMISSIONER SPITZER: Well, playing devil's advocate, how do you respond to Mr. deJesus concern that as economics change over time the joint ownership format actually becomes unwieldy and more difficult?

MR. GESCHWIND: We have not experienced that. In our case I don't think that's a concern that should stop the Commission from allowing for opportunities for joint investment.

MR. DeJESUS: I mean I would just say just like any other transactions there are good deals and bad deals. You don't want to be forced into the bad deals and you want to allow for negotiations so that folks can get into the good deals.

MR. INGERSOLL: I agree with both. There is a large jointly owned transmission system, the Georgia Transmission System, and I'll attest to the fact that it is extremely complex, although we don't serve that area. But the contracts and the relationships to do jointly-owned transmission are very complex and I think you need to factor that into your thinking. It's not an easy thing and as you go forward there are many, many factors to deal with. If a system has to be upgraded, now you're back into a contractual negotiation again if that particular facility requires upgrading. So at least I think in our area in general the transmission providers are willing and able to build the necessary transmission.

I think that there are situations where jointly-owned transmission can be helpful, particularly where there's a large transmission facility possibly associated with a remote generator that needs to be built to serve multiple parties. That can be very helpful to jointly build such a facility. But I think it's hard for us to see a progress on a requirement hold an open season and slow down the process of getting transmission built would be overall a benefit. That it would create more complexity and more delay.

MR. KERR: Commissioner, let me just jump in and reference the CAPX, the comments earlier from CAPX about the legislative changes that they identified through the process and then were able to go find solutions for and one of the concerns, I think -- and speaking more from an southeastern commissioner -- but I mean the comments are we don't think you ought to mandate joint projects. I think in addition to the contractual complexity there are likely legal complexities. Those with respect to cost allocation and jurisdictional issues, even at the local and state level. There are also opportunities. Similarly the different types of entities you might have in a project provides probably some financing opportunities, cost of borrowing advantages and so forth. But it seems to me that mandating potential solutions in the context or at the outset of really trying to develop comprehensive planning processes runs the risk of overly burdening the process at this stage.

They way we've talked about joint ownership in the North Carolina process has been let's get comfortable with the quality, the optimization of the planning. Let's identify what those problems are, then lets' look at what the potential solutions are, the options and understanding, like in CAPX, we may need to go in and tweak state statutes to address the timing of recovery for the regulated companies versus others. So my point is just simply to say I would be a little bit weary of overburdening the quality of the planning process of such a mandate versus let's improve and at some point down the road when we feel good or have improved the ability to identify problems. This fits into the kind of solution category to be worked out by the parties or where us regulators need to get involved or legislatures. That's part of it as well.

COMMISSIONER SPITZER: Commissioner, one facet of the regional issue is in lesser jurisdictions where the presence of public power you have the opportunity for tax exempt public financing, so you save a couple hundred bases points and that's were major benefits -- it may not be universally available, but I know in some areas, entities were formed to take advantage of the public, either tax increment financing or tax exempt financing.

MR. KERR: Right. And it can work. We've done this on generation in the '70s, the joint action agencies. I mean it is as much an opportunity. I think for purposes of why we're here today it seems to me it's a bit of a timing issue about the planning process versus kind of skipping ahead or burdening it too early with possible solutions would be my take on it.

COMMISSIONER SPITZER: Please.

MS. JOHNSON: Xcel Energy has a lot of experience with jointly-owned projects with a significant amount of transmission in the West. In Colorado where we have that joint ownership. And albeit. some of those contracts are very complicated, they're also very successful. And through our regional planning efforts, we continue to explore joint ownership possibilities. Xcel believes that it should continue to be voluntary and not mandatory. And as Commissioner Kaul said, it can be overly burdensome in the onset of a project just as a prescribed open season could be.

We believe that the focus of an open season is really to right size a project and ensure that you have the inputs of all the various stakeholders as you go forward and build a project. Much of what determines, in terms of the economics and who participates ultimately, is the economics and that costs assurity that Mr. Kaul also spoke in Minnesota. We're also seeking the same type of cost assurity in our recovery from the State of Colorado as well as Texas to make these investments. And I'd also like to say that ownership does not imply usage rights. It implies an opportunity for transmission service revenue.

MR. KORMOS: I probably offer just ones that are practical just sort as an independent planner. I think one thing that would be important, though, I wouldn't want to lose the contractual obligation to build, which we have. I mean we know who is obligated to build and I would not want cloud that with a process like this and I'm thinking I'd be very cautious about that.

The other concern I have is just from a practical. I'm not sure how we would pick the winner. I'm not sure right now even if we have two transmission owners who want to build the same project how we decide which one should build. That's going to be a very real issue for us that we need to deal with, let alone if we started to get into joint ownership models and financing models and how we would ultimately evaluate that. So just from a practical state, I would caution against. I'm not sure of the criteria we could even to evaluate these kinds of proposals.

MR. GESCHWIND: I've just got one final comment. I think it would be a great problem to have to have to figure out which transmission owner would build a project because you've got more interest in building a project than projects available. That is not the experience where we come from. I think it's just the opposite and I think the joint ownership opportunities that we have, I think, were the impetus to get some of these projects going forward and that now we have a chance to bring the stakeholders and the users of the system together to put some skin into the game. And absent that, I think some of these projects that we need going forward are almost too large for individual companies to step up and take on by themselves.

MR. KAUL: Just a quick couple of comments. One is on these joint ownership agreements. Yes, they're complex, but they're very manageable. We've been doing that for years and years.

The second thing is on the mandate, at least I think from the CAPX point of view, we have sort of a delicate thing and harmonic convergence and it all seemed to work somehow and we wouldn't want anything to happen that would upset that.

COMMISSIONER SPITZER: Harmonic convergence. That's a new one.

(Laughter.)

COMMISSIONER SPITZER: Anything else on that?

MR. WYBIERALA: Yes, I'll just make one comment from a generator's perspective and we don't normally consider ourselves in terms of transmission thinking that way of developing transmission. We also have issues related to if we had transmission there's a tariff issue there. But if it made sense from a generation perspective to jointly participate in transmission, I think we would welcome an opportunity to do that and evaluate the benefits of that investment.

COMMISSIONER SPITZER: Mr. Kormos identified the obligation to build and that's been a historic state issue and obviously is a flash point with regard to federal jurisdiction, but as the NOPR has evolved, we now have the overhang of reliability and particularly with regard to interstate and you've got this circumstance where you could have a penalty, ultimately potential for substantial penalties. There are jurisdictional limits on a federal mandate, but I've been reflecting on overhang of reliability with regard to interstate and I'd like you to discuss how you see the interrelationship between reliability and potential -- whether it comes out of the reliability focus or this proceeding -- issues having to do mandatory obligation to build coming from outside what has been the generally recognized role of purely intrastate procedures.

MR. DeJESUS: Commissioner, we have an obligation to build as well in New England. It was voluntarily entered into, but it's been very -- well, it's served us well. I mean a lot of folks think that the obligation to build is -- we come up with a plan, list all the projects and now the TO has to build those projects in the way that plan, that particular plan is laid out and that's not how it works. Planning is an evolutionary process. From year to year, things change and as you get to the point where you actually start building, you look at things a little bit more closely.

One of the things that transmission owners get from a -- and we like to use the word "commitment to build, commitment obligation." I'm not exactly sure if there's a difference. You get to specify the terms under which you would build. In New England we have in our transmission operating agreement a provision that lays out transmission owner obligations, ISO obligations to fulfill what's in the plan. Those things include the ability to recover your costs. What happens if you don't get siting approval? And so if we can get to that level of detail with this commitment to build, it actually is a useful thing from a transmission owner's perspective.

And also I want to get to your reliability point and that's this. Now we don't think that planning should be exclusively reliability driven and we wouldn't hang our hook on the commitment build on just the reliability obligations that we have. We think we have a broader responsibility to our customers to ensure things like congestion reduction and that commitment to build would extend to that as well.

COMMISSIONER SPITZER: I understand that you've got a scheme that embraces more than simply reliability and you want that paradigm to be broader, but I guess my point is perhaps the reliability issue can invoke certain changes in what might be limited commitment to build.

MR. DeJESUS: And I think that helps, but I mean let's face it, if the plan were truly a collaborative process and the transmission owner sanctioned the plan as well, then you wouldn't have any problem getting a transmission owner to agree to build what's in the plan. I think that's fairly simple. So it's very easy for us to commit to an obligation to build in our arrangements because we knew that, at the end of the day, we would support what's in the plan as well beyond just sort of command and control mandates or the threat of penalties.

MR. KAUL: Just a quick comment on at least our situation, which is the obligation to serve was kind of the heart and soul of our motivation as a group of utilities and reliability was our No. 1 concern. Our planning is a subset of the MISO planning process and I don't think it's been tested yet, but many people argue that MISO, at least in our case, that RTO has the ability to require transmission to be built. So I don't know if that's going to be borne out or if it's ever going to be tested, but at least in the RTO situation you might have that covered.

MR. GESCHWIND: I'd like to just briefly offer the TDU perspective on this. I think there is -- you know, we talk about the obligation to serve. I think there's instances out there within the TAPs ranks of situations where the transmission providers are not planning to serve their network loads to the same level of comparability that they're planning to serve their own loads. And in the written comments that we provided for this, at the end of the comments and in the previously filed TAPs comments, there's a suggestion there's one way to provided maybe some backstop support for this obligation to follow through with the transmission plans and ge the facilities built because that's -- the plan does nothing if the facilities never get built.

We'd like to see the transmission provider have an obligation to accept service to a network load if that load were the transmission provider's load it would be accepted and it should be accepted if it's a network customer's load. That gets to some of the granularity differences that exist in the fact that most network customers on a system have discreet loads and discreet resources. They may be intermingled inside a transmission provider's system and it's easier for a transmission provider to come up with the combinations of paths to serve a load if it were their load easier than a TDU with these more discreet loads and resources. So if there's an obligation, as outlined in our comments, for the transmission provider to accept that request if it would be accepted if it were their own load and then to the extent necessary that there may be redispatch costs that should be shared on a load ratio basis within that network I think that starts to send the right signal that the system needs to be planned with facilities that are ultimately built to address not just the transmission provider's load, but also the load of the network customers.

MS. JOHNSON: With respect to the obligation to build, most of our plans are based around the reliability. In addition to ensuring that we have continued access for our consumers to low-cost energy. So the economic piece is in there and that covers definitely the CAPX 20/20. It also covers the Colorado long-range plan as well as what's going on with SFPP and their long-range planning efforts. Obligation to build under an RTO it may, in fact, be mandated if SFPP comes out with their ultimate plan on what's required to meet all the generation and load obligations.

I just want to respond to Mr. Geschwind. Our network loads are treated on a comparable basis and so irrespective of whether its a native load or a network load customers they're all modeled into the system and the plans to meet those loads are developed as a whole and committed with the same amount of certainty whether it's a native load or another network load customer.

MR. KERR: I'd just say briefly what is reflected in the planning collaborative that we have in North Carolina was really to bring all the load on par from with not a legal obligation to build. We wanted it planned for on a par basis and that's really kind of what drove the -- the only other comment I would say briefly is with the recent federal statutory changes and this body's involvement in reliability my personal view and my musings have been that I view this as a very positive development because I think to some extent this agency viewed transmission previously more in economic terms, given its role and I think the square -- giving you squarely responsibility for reliability puts you much like the state view has been on reliability. So it seems to me that we each answer to those to whom we answer on reliability and this ought to provide some harmonic conversion of our views of some of these issues. So I've viewed that as a positive aspect of the Energy bill in that regard.

COMMISSIONER SPITZER: And the regional reliability entities could be an intersection between the new federal role and the traditional state role. Do you see an opportunity there?

MR. KERR: Yes, I think it's going to happen somewhere. I mean we'll do it however. I think the key is, if the lights go out, we're each going to get phone calls from those that we answer to asking what happened and I think that's the kind of things that motivate us and I think ought to motivate us to view some of the problems and issues similarly.

MR. LOOCK: Just from a reliability counsel perspective, if a project is mandatory or non-mandatory, I'd hate to see any project decay the reliability of an area. If a project is mandatory to be built possibly one of the stipulations is mandatory at least be conserved if not improved. But if a project is built and the reliability is decayed, I don't understand what we're doing here. We're losing ground.

COMMISSIONER SPITZER: Mr. Chairman, one more item very briefly, which is the scope of the third party, independent and again, leaving aside jurisdictional issues, instead focusing on whether they're any economic or structural or engineering issues attending to the third party participation. What would be your insights on that? It's not like law school. We don't call on people.

(Laughter.)

MR. DeJESUS: I went first last time.

COMMISSIONER SPITZER: You're excused.

(Laughter.)

MS. JOHNSON: Xcel Energy's comments with respect to third party participation is that it should not be mandatory or even required. We've been very successful in our endeavors of regional planning without that third party overhang and I think it could actually prolong the process, add more cost to the process and not necessarily provide a benefit.

MR. KERR: I would just say that I think, though, that there are equally good reasons. It might be helpful, for instance, on confidentiality. I mean you might need someone to whom you can work through on critical infrastructure or confidentiality. So that's short of saying it should be mandatory. Briefly, I would relate the story that we are doing a renewable portfolio study in North Carolina. We've called everyone in the room. I mean we've Vern and his guys and we've got the environmentalists and we said we're going to do this. We're the independent party. If there are problems, we will decide. This is not a democracy. Don't get knotted up, but it's going to be our call. Hope we don't have to see you and I promise you a year and a half later we haven't had to see them. So these things can work. Whether you need to mandate that at the outset versus let the process reveal places where they do need someone. They need to come see us or they need a third party and whether that is the reliability, regional reliability organization or whether its Gestault is doing that for the North Carolina process. I think, again, the types of processes we are contemplating here will reveal whether and to what extent and what type of independent third party as opposed to you all being able to discern that right now I think is the feeling of the state.

MR. KORMOS: Obviously, giving a little southern bias view. But obviously, we do believe independence does eliminate some of the problems discussed about load being treated equitably, the nature of the studies and favoring one participant member or participant over another. The confidentiality issue is pretty much non-existent in our planning process. So I think there are a lot of good, valid reasons to look at independence.

MR. DeJESUS: We've been beating the drum for independence for a while now, but I guess where you came out in Order 679 is right. An independent entity is consistent with or superior to what's in the OATT and there's lots of reasons. They're all in Mr. Kormos's testimony and practically every filing we've made at the Commission in the last several years.

I mean the one thing I will say for now is that having an independent entity gives a little bit more comfort to folks that what was produced in the plan is in everyone's interest. You have somebody's who -- well, let me just leave it at that.

MR. KAUL: I guess on behalf of Great River Energy, as a MISO member, we believe -- I guess our planning goes through a MISO process. It's very transparent, lots of stakeholder involvement and I think that should be sufficient.

COMMISSIONER KELLY: Can I ask a follow-up question, Marc, on that?

Jay and Sandra, in WEC, has there been discussion about having an independent entity involved in regional or subregional planning processes?

MR. LOOCK: I believe TPSI is going to be that independent body in the West as in collecting the data and making that data available to entities that want to use it in their transmission planning.

COMMISSIONER KELLY: Have they been the facilitator? I didn't understand your answer. They're proposing to do that or they are doing that.

MR. LOOCK: They are and proposing to do that at a higher level.

MS. JOHNSON: Yes, the TPSI will facilitate that regional planning. But I'd also say that the ARMAS Group did have that third party type of structure and then the SGWI planning process also had a third party. But I would call that more of a facilitating role in that the parties that were participants it allowed for a very large project or study to be conducted and in a fairly efficient manner, but I don't believe it provided any more transparency than would have normally been provided through the regional state processes.

COMMISSIONER KELLY: Did it provide any other benefits? Did it provide any benefits?

MS. JOHNSON: I would say that it did provide benefits in that it lessen some of the workload of some of the involved parties.

COMMISSIONER KELLY: Did it increase trust in the process or more buy-in by the participants?

MS. JOHNSON: I'd have to compare it to some of the other planning processes where I've been involved where we didn't have that and I wouldn't say that there was necessarily more buy-in. So I think it's just critical that stakeholder input is allowed for at the beginning of the process and through the process so that we get that collaborative effort and that buy-in regardless of a third party.

COMMISSIONER KELLY: Vern and Jim, in the Southeast, have you had the experience of independent facilitators or of another role of an independent in any of your planning processes?

MR. INGERSOLL: Yes. We have. Gestault operates as our independent third party in the North Carolina collaborative process. Their role is as a facilitator to the process to help us reach consensus on issues. As Jim mentioned, the process we've set up has a voting structure of the LSCs and we have found that useful. I think it's important to us in this collaborative approach to reach consensus and not to vote, though we set up a voting structure. And I think having the third party has been helpful to us in that regard to explain things to the parties. Much of the initial process of folks who are not transmission planners is to help them understand the transmission planning process and we have in our process what you might call a policy kind of person from the third party as well as an engineer-type person. So it has been helpful.

In Florida, they have implemented an region process using the Reliability Council or the planning group reports to the Planning Committee and they essentially use the staff to provide that separate viewpoint from the transmission owners. So we think it's useful, but I think it's also important to recognize that the transmission providers, whoever that might be -- if they're vertically integrated or an RTO -- have certain obligations, both to their commissions and under the OATT. So that has to be factored in to how a third party functions.

COMMISSIONER KELLY: But your experience in collaborative process with a third party facilitator was a good one?

MR. INGERSOLL: Yes.

COMMISSIONER KELLY: It would seem to me that that might eliminate the need for a dispute resolution process or system.

MR. INGERSOLL: We do have a dispute resolution process also, which involves some of the North Carolina folks.

COMMISSIONER KELLY: Is that a formal process?

MR. INGERSOLL: Yes. They're designated -- what we have in our collaborative is a contractual arrangement amongst the parties that fund it and there is a formal process, but we've never had to resort to it yet -- knock on wood. And again, I do believe the third party has been useful to us in overcoming some of the issues that arise in allowing us to come to agreement on how to proceed.

I don't think it's absolutely necessary and it depends much on the structure and I think the really important thing is having the folks at the table so that they can see and understand what's going into the models and have a say in what goes into the models. Once that happens, a lot of the concern about discrimination goes away because they begin to see that what you're really doing is having and being forced to make engineering judgments. None of us have a crystal ball to really know what generation is going to be built. When is it going to be built? Should we commit to build this line yet or should we wait and see what happens next year? How much reserve transmission do we need? So I think the really important part is having folks at the table.

MR. KERR: Commissioner, I would just add they do have a facilitator. I don't think Vern said this directly, but in the governance process they each of the four load-serving entities have two representatives. You get to eight. As you all know, an even number can be problematic in voting and so the facilitator is the ninth vote. There were really practical reasons that this independent entity came in, but they came up with that themselves. I mean we didn't say we want it done this way. It was not prescriptive. It was we want it to be independent. We want it to be fair. We want you all to feel good about and we want to feel good about it. Understand that -- you know, I think what's driving a lot of this, at least in the Southeast, is that we understand we're facing an era of significant investments and we want to make sure that the decisions we're being asked to make are based off optimized planning, efficiency. What are the options and what is the optimized planning? And so we wanted to have confidence in the system. What that required, I think, might be different in different places and that's what I would urge you all to be differential enough to let that be decided because I think it's especially true if you all have indicated that you think it is important, if the state regulators have indicated this is important, I think we'll get what we want. Now how we get it might vary from place to place and what it looks like might vary. But I think with some combination of the overarching desire for this to be really optimized planning I think is what we're talking about, removing the black box, letting people have confidence in what are really engineering truths. I mean us lawyers can split hairs and maybe even shade things a little bit. These guys don't tend to operate that way and I think, from the state perspective, we're concerned that this be done cost effectively and so I think being too prescriptive runs the risk of maybe not getting the result we're interested in.

COMMISSIONER KELLY: Thank you.

MR. MOELLER: Mr. Chairman, given the time, I'll be brief. I admire and support what Commissioner Wellinghoff talks about in terms of Demand Response and that focus. I also feel strongly that the country is way behind generally in building transmission as Mr. deJesus referenced and it's catch up time. So we need to be making these investments in a hurry. My challenge and my focus is kind of on enforceability of regional plans since rarely does anyone work for a regional form of government. They either work for a state or they work for maybe a regional entity, but in terms of who you answer to it's a challenge when you're talking about regional plans who can really enforce them.

Now there have been references already to whether obligation to build, whether it's an independent entity, but if you could each briefly comment on that concept, along with the fact that, if you don't have an independent consultant involved, is there the potential for anti-competitive decisions being made?

MR. DeJESUS: Commissioner, our obligation to build is in our transmission operating agreement with ISO New England. It's Schedule 3.09, which was filed here. I assume, as we go forward and whatever comes out of the NOPR on planning will be in the tariff and so that will be this Commission's responsibility to enforce. That's not to say that the states won't have a say in it, in fact, we'll see them in the planning process and ultimately when we go to site facilities.

One thing a plan can do and the reason why we're comfortable with a commitment to build is it will give you a piece of paper that says this is the collective wisdom of the planning participants that this is the right thing to do and we can take that in whatever forum we go to and I really think that's the helpful piece of planning, at least from my humble lawyer's perspective.

MR. KORMOS: I mean I think it's a very real issue. I think we have the benefit of being independent. We have it being very transparent. The states are involved in and yet I think it will ultimately be a fairly big challenge to get the infrastructure actually built and through the state process. We have filed actually with DOE for the quarter designation and we are very hopeful we will get that and ultimately we hope to get through the state processes within the year, but believe the backstop is important also. So I believe it's a very legitimate issue and I think the independence and the openness of the process so that the information gets out there so people understand the problems we're trying to solve and what the real options are. In particular, some of the issues we're dealing with the options are very, very limited at this point other than building.

MR. KERR: Commissioner, the regional governance problem has vexed this country for a long time. We've relayed my state's dismal compliance with its obligations under the low level nuclear waste pack. I've volunteered that if we ask to join a regional compact with you, don't take us up on it.

(Laughter.)

MR. KERR: I think that's a problem. And Joe and I've talked about this. We have the system we have. It's a federal system and it has problems and these are the kinds of things that it reveals. I think, essentially, Congress has answered the question, which is some level of federal backstop. We're not going to not build the things we determine through some fair process we have to have and this is how we'll do it. But otherwise the structure we have is going to have to work.

I think what we are left with is to try to come up with, in this context, some sort of effective regional planning processes that again I keep going back, I think, to some combination of shared support from you folks as well as the relevant states within the region is about as close as we can come effectively. I think compacts there's a provision I know in the bill. I just don't see people pursuing that option of more formal regional governance or requirement.

I guess I'll stop there.

MR. INGERSOLL: Having been at this regional planning stuff longer than I care to remember, it does work but it's sort of like sausage. It's not very pretty to watch it made, but transmission does get built. One of the main things, I think, that prevents discrimination, if you will, or transmission not getting built where it should be built is that the whole process, at least in the Eastern interconnection, which is what I'm familiar with and I'm sure it's the same in WEC. The plans of individual systems are rolled up usually into subregional plans. They're studied again and rolled to regional and multi-regional plans, and it's simply impossible to hide a problem on the system. As to our collaborative with Florida on regional process, as you get more folks around the table who are saying, yes, that's the right load. That's my load, verifying the right load's being used and yes, that's where my resources are going to be coming from, you begin to really address a lot of those issues because the process is open and people see and agree on what's going in.

Once the problems are identified, what we've found is that they do see the light of day and usually what happens is initially there's some reluctance. Well, I'm not so sure that's really a problem and you study it some more. But eventually, if it is a real problem, it's there and the transmission providers, in order to meet their reliability standards and other things and the pressure from their customers in the industry, are going to fix the problem. That's been our experience that the problems do get fixed and the transmission gets built.

MR. KERR: Commissioner, the other part of your question was about competitiveness and let me just quickly say -- I mean obviously and I think I mentioned that in response to Commissioner Spitzer, an independent entity can help with some of the concerns or become an appropriate conduit or gatekeeper on the confidentiality and the anti-competitive. Similarly, what we have understood and we have filed in the comments, but it revealed itself in the SRUT process is that your existing standard of conduct requirements may, in fact, be an impediment to the communication and so we've asked to consider a safe harbor. We ask for some sort of safe harbor be created. We do that fully supportive of your goal of preventing discrimination and anti-competitive behavior and quite frankly, my view is you all are best to figure out how to fix your own rules or to create the harbor you need. So it's with full support of the principles of the standards of conduct, but also acknowledgement that as we seek to improve communication that's a place that I think you all can provide everyone with some help and some guidance.

MR. WYBIERALA: Let me just add from the generator's perspective. NRG, as I stated before, has plants in areas where there's independence and in areas where there's not. It's like night and day. It's just something about having an independent facilitator there with the expertise that understands the issues of the transmission owner and understands the issues of the generator, and the process just tends to get worked out more rather than -- you know, you just get frustrated because --

someone mentioned the black box. There is that factor in that you're constantly trying to understand the transmission planning process that the transmission owner uses and understand how they've come up with what they have and when there's a dispute the only way to resolve it is to come here.

But also let me make another comment and that is let's also not lose sight of the fact that over the last 15 years a lot of the generation has been gas, combined cycling and peaking plants that you could build in 18 months or two years, and that has probably worked against the traditional planning process as I practiced before I worked for a generating company, which was we used to looked out 10, 15, 20 years and figure out what the load resources requirements were and now you can put generation in, in such short notice, wherever you needed, the transmission planning horizons got compressed and became very short and you don't have the economies of looking out further and making the right decision. But in saying that recently I see happening is that there's a lot more new projects that are coming on that are not short-term gas-type projects. They're nuclear. They're IGC, coal gasification projects. There's new coal plants coming. These plants are going to take years to build. There's probably a minimum of at least a five-year horizon on any of these plants and there's an opportunity to squeeze more economies out of the system by working with the generation side to come up with plans that bring all that in because you have more time to plan for it. You just can't say it's going to be there in two years. I don't have to do anything. So that would be my comment is to just recognize that the generation plays a significant role with how the transmission system does evolve.

COMMISSIONER KELLY: Joel testified that while the Commission should not tell regions how to allocate their cost, the Commission should direct individual utilities within each region to come up with a cost allocation proposal that either filed in individual utility tariffs, complimentary tariffs or in one regional tariff. Do any of you disagree with that proposition?

MR. KAUL: I don't disagree. I guess that was what made the CAPX projects go. We needed a regional cost recovery mechanism to be decided by somebody and that helped us.

MR. KORMOS: I don't agree as well, though, I think in my area we might need a little more help on just even the principles. I think we're still struggling on what are the principles that the Commission wish for cost allocation, some guidance on that and then hopefully a resolution of cost allocation. My biggest fear now is we're starting to litigate case-by-case every transmission upgrade and I really think that's going to be counter-productive going forward, so the sooner we can resolve that in its entirety I think the better.

MR. INGERSOLL: This is a difficult issue we think. We have discussed in the collaborative and we've recently had what we call the Central Florida study in Florida where the upgrades covered a large number of systems and I don't have the answer for you. I think I would advise you to avoid being more prescriptive than the OATT currently is. There's a good argument for rolling into the rights of the transmission owner in the area. He's building whatever he builds and letting it go at that and in many cases that's kind of where it comes out when you have a process. But there are other situations, particularly if you get into a large, multi-state or multi-regional transmission line where potentially the folks benefitting are not the folks through which the line is passing. That might need to be different, depending on the circumstance.

I think it's going to be awfully difficult for the transmission owners or the Commission to lay out this firm rule that fits every situation. I know that's not a very good answer.

COMMISSIONER KELLY: Actually, my question was not -- and I think Joel testified -- not that the Commission would lay out a rule, but that the Commission would require the utilities to have a rule.

MR. INGERSOLL: I think that's just as problematic because it's the 80/20 thing. I could say, yes, 80 percent of the time we ought to do it this way, but there are going to be these other projects where nobody's going to be happy if you go down that route. So how do you have that flexibility?

COMMISSIONER KELLY: Could you have the flexibility by having a general rule that allowed for exceptions? I'm swayed by the argument that if every single transmission project has to be negotiated in advance what the cost allocation is that we're going to spend a lot of time negotiating when we should be talking about what the project should be.

MR. INGERSOLL: It is a trade off, but I think that I would err on the side of caution because, in general, what we've found is that at the end of the day, after the discussion, folks are happy to roll it into their rates because they see a general benefit. I don't know how you would spell out that exception -- you know, how I as a transmission provider would spell out what that exception is. We've just begun a discussion in our collaborative if we could have a policy and I think maybe if we were to go down that road, which I'm afraid of, it might be better to ask us to articulate a policy rather than a firm, this is the only way it could be done.

MR. KERR: One of the things that happened to us -- I mean you cant' talk about this for five minutes without getting the cost allocation and what we did -- Commissioner Irvin and myself talked fairly early when we first called these folks in to talk about this and we made a decision that if we did too much there we were going to kill the process because that's all anyone would ever focus on. Maybe it was hope over experience, but we said let's talk only about planning and save that for another day and it took some of the pressure off and then the hope was that with better understanding and confidence in the planning that then those decisions would become more apparent to the participants and a little bit less knotty. So that's a bit of advice from our experience that we didn't want to throw that log on the fire and break it all down. I mean it was to set it aside a little bit and be hopeful it would get worked out.

That said, I do personally support some reasonable efforts to make those decisions on some appropriate regional -- you know, whatever the area is that's implication so that we don't let the perfect be the enemy of the good. I mean I think to some extent we need to say, look, we're going to do the best we can. SPP was able to do that. I think they did two-thirds, a third and I think that if you just do the best you can and if you say, look, we will look at this again. The nature of projects might change over time. I mean what was economic one day becomes reliability. I think some sense to the changing nature of it and some understanding that, if we do two-thirds and a third and it's not right, we'll go back and we'll look at it and change it. I mean I think a reasonably close or reasonably good principle subject to frequent review and sensitive review is certainly better than case-by-case seeking the perfect that by the nature of the parties positions there's no perfect answer.

COMMISSIONER KELLY: And a case-by-case might work much better in a situation like you described where it sounds like it was relatively confined and it was one state and one commission and they were probably going to have to get it built one way or another.

MR. KERR: Yes, I think so. My belief is we would hopefully get some sense that there is some general rule so that as you are doing this that people are comfortable with, but don't worry if this isn't perfect because we'll look at it. I mean there will be some chance to tweak and to make changes and based on actual use of the facility and so forth, and just that people will be treated fairly at the end of the day. But we've got to do something here in order to get these projects moving.

COMMISSIONER KELLY: Right.

Is the situation of long lines different? Does it demand cost allocation in advance more than other situations?

MR. KORMOS: I think when you start to look at backbone facilities across multiple state, No. 1, the size of them. We're allocating costs for hundreds of thousands, even millions we didn't have very much objection to whatever method we used. When you start talking billions, people pay a whole lot more attention. I also think, though, that the benefits become much larger to quantify, particularly, when the benefits are very far into the future. These lines can potentially take 10 years to put in place and so when you're trying to look at who's going to benefit 10 years from now there's a lot of entities not even sure they'll be in the business in 10 years, so it becomes very difficult. So I would agree that the longer the lines, the bigger the lines the bigger the problems.

MR. GESCHWIND: I would agree as well. And to echo the comments on CAPX, it was this regional cost allocation I think was the thing that put us over the top and it is very different for long lines just because of the same reasons mentioned. If I'm going to invest in a project that's going to be benefit multiple systems, I'm not going to want to foot the bill for that. The cost allocation I think it is a critical component. We just want to add of interest to us is this opportunity to invest. From our perspective it's one thing to be assigned a portion of a project's cost. It's another thing to be, at the same time, given an opportunity to invest maybe up to a load ratio share, for example, in that same project to offset the costs that we are going to be paying, offset that cost through facilities credits back to us.

MR. DeJESUS: Commissioner?

CHAIRMAN KELLIHER: Go ahead and use one of my three minutes.

(Laughter.)

MR. DeJESUS: For the record, I don't disagree with my prior comments. But I think that the big issue has to do with certainty and that is a big problem for longer lines, but it's certainly a problem in smaller substations.

For substation upgrades, as well, I would respectfully suggest that we need a cost allocation for all those types of facilities.

And let me put in a plug for the New England cost allocation, which got about 80 percent of stakeholder approval when we filed it. That cost allocation breaks down facilities, based on function. It's not an arbitrary 80/20, although I guess that works for some folks.

And I would commend Verne to look at that, because I think it's a very engineer-focused type of cost allocation. You look at the function and determine roughly, who the beneficiaries are.

COMMISSIONER KELLY: Thanks.

CHAIRMAN KELLIHER: Do you have a followup?

COMMISSIONER KELLY: I was just going to say that that was very good lawyering, to bring the engineers in.

(Laughter.)

CHAIRMAN KELLIHER: But do you think the New England allocation approach has worked? Is more transmission being built as a result?

MR. deJESUS: Yeah, I would think so. I'm not prepared to -- I mean, we've got $3 billion in our plan. What it has done, it's cut down on the amount of disputes we have on a project-by-project basis.

Now we're not arguing about whether a project should be built or where it should be routed; we're arguing about things like undergrounding.

CHAIRMAN KELLIHER: Thanks. I just want to make one comment, and then I'm going to ask a couple of questions that hopefully will lend themselves to yes or no answers, just so I use my time efficiently.

But a comment: Picking up on something Jim said at the very beginning, that he observed that the state and regional planning efforts preceded the NOPR, that was absolutely correct. In fact, they inspired the NOPR.

We looked at some of the success at the state and regional levels, and we decided to reinforce it and replicate it, so I think that was a good observation.

I also want to credit SEARUC, in particular, for that meeting, the two-day meeting that we held. Again, it was regional transmission planning.

As soon as we put out the NOPR, there was no hostile reaction at the state level. It was a very businesslike, workmanlike approach of, well, let's explore this; it seems like a good idea.

FERC is trying to pick up on some of our successes, and let's spend two days looking at how we can actually make it work in the Southeast, so I thought that was a very productive exercise.

So let me get to my yes or no type of questions.

A lot of the cost allocation questions came up. That was something that I was going to ask about.

Joel was saying that it really needs to be decided in advance. I think Ms. Johnson said that it really can't be decided in advance. At least in the West, it's always been decided, project-by-project.

But that's really just for the major interties, right, not for routine projects, but, you know, the Pacific interties where those were project-specific cost allocation decisions, I suppose.

MS. JOHNSON: Yes, as well as some of the larger joint projects.

CHAIRMAN KELLIHER: Okay. One issue we really haven't talked about, is what's the geographic region? I think you all had different views on that.

I think Jim said more than one utility; someone else said more than one control area. I think someone said NERC regions should kind of be a default, but I think Mr. Ingersoll said CERC is too big.

So, now, in WECC, you have six subregions, and I have no idea how they developed, whether they have been static or whether they've actually been a little bit fluid over time.

But are there any lessons we can learn in WECC, and then apply to CERC, and how do you develop subregions, if, indeed, CERC is too big, what would the right subregions be?

MR. LOOCK: Well, I think that in WECC, the reason we have subregions, is because we're so big, and the resources are different in different areas. We have resources in the West that seem to be in the Rocky Mountain, Montana, and Wyoming areas, but the load --

CHAIRMAN KELLIHER: Is that decided by flows, by transmission flows, to some extent?

MR. LOOCK: Some part of it, yes.

CHAIRMAN KELLIHER: Okay, well, I didn't succeed on a yes or no answer on that. I didn't frame the question properly.

(Laughter.)

CHAIRMAN KELLIHER: Let me ask question that does lend itself to a yes or no, and I'll try to have a default, so that silence means yes.

(Laughter.)

CHAIRMAN KELLIHER: So you don't have to be silent, though. That's a fair way to structure it.

I think Joel said, and perhaps others have said that regional and joint planning should look not just to the economic projects, but at -- not just at reliability projects, but at economic projects. And so the question would be, do any of you disagree with that? Do any of you disagree that regional and joint planning should look at both economic and reliability needs? Again, silence means assent.

(Pause.)

CHAIRMAN KELLIHER: Okay, for the record -- oh, Mr. Ingersoll?

(Pause.)

MR. INGERSOLL: My response would have to be a "sort of."

(Laughter.)

CHAIRMAN KELLIHER: Sort of? Okay.

MR. INGERSOLL: In other words, I don't think it's appropriate to ask transmission planners to do production cost analysis and so on.

So it depends on how you define "economics." On the other hand, we do in the Collaborative, for the LSEs, look at interface capability and what it would cost to make various upgrades, so that they can make the economic choices, versus the transmission planner making those choices for them.

CHAIRMAN KELLIHER: Okay. We have to leave this room in two minutes, and we have a lunch, and so let me try to ask one or two really quick questions:

A number of you criticized some of the RTO planning efforts; Joel criticized New York ISO, and Mr.

Geschwind had a reservation about MISO's planning efforts.

And I have just a question, really, for Mr. deJesus and Mr. Wybierala: Which RTO planning efforts do you really think are the best right now? Is it the man in between you?

(Laughter.)

CHAIRMAN KELLIHER: Is it New England?

MR. WYBIERALA: PJM.

CHAIRMAN KELLIHER: PJM? Joel?

MR. deJESUS: Is this a yes or no question?

(Laughter.)

CHAIRMAN KELLIHER: Well, it's a one-word answer. You can take PJM or -- I guess two words -- New England?

MR. deJESUS: We like elements of New England and PJM.

CHAIRMAN KELLIHER: Okay, okay. And I think I'm really about out of time. Staff, do you have one minute of an excellent question to finish this session?

(Laughter.)

CHAIRMAN KELLIHER: No? Okay. I want to thank everyone for their attention. I want to thank the panelists for their help, and we have lunch upstairs for the panelists on the 11th floor, and we will begin promptly at 12:30. Thank you.

(Whereupon, at 11:48 a.m., the Technical

Conference was recessed for luncheon, to be reconvened this same day at 12:30 p.m.)

A F T E R N O O N   S E S S I O N

(12:33 p.m)

CHAIRMAN KELLIHER: I think my colleagues will be joining us shortly, but we might as well try to stay on track. We're here on the second panel. We're going to discuss ATC-related reforms and why don't we start with our first panelist, Mr. William Lohrman, Managing Director, Prague Power on behalf of the North American Electric Reliability Council. Thank you very much.

MR. LOHRMAN: Thank you, Mr. Chairman. I'm pleased to be able to represent NERC and to provide these comments in response to the issues and questions raised in the Commission's agenda for this conference.

NERC supports the Commission's efforts to ensure transmission services are provided in a non-discriminatory and just and reasonable basis. NERC further supports the Commission in encouraging the electric industry to work towards increased communication, coordination, consistency and transparency in the calculation and application of available transmission capability and related ATC values, while at the same time protecting the reliability of the bulk power system.

NERC also agrees that there is a need to continue the enhancement of the calculation of ATC and ATC-related values to support the wholesale power market while maintaining adequate reliability for all users, owners and operators of the bulk power system. NERC also supports the recommendations of it's long-term AFC-ATC Taskforce, the Commission and industry to add increased standardization and consistency to the current NERC reliability standards on ATC and ATC-related values. However, NERC urges caution to ensure that the ATC calculations and their applications are consistent with other NERC reliability standards, regional reliability criteria and transmission owners, operating and planning criteria.

Since NERC filed its comments on the Commission's NOI, NERC has undertaken a review and a revision of its standards related to ATC calculation and coordination. Currently, NERC has under active development two sets of existing standards dealing with ATC and its ATC-related issues and CBM and TRM-related issues and NERC is coordinating its efforts with those of the North American Energy Standards Board on a related proposed business practice standard following the NERC/NAESB Joint Standards Development Coordination Procedure.

The proposed changes to NERC's existing modeling standards would add a requirement for transmission provides to coordinate the calculation of the TTC, ATC and AFC and require that specific reliability practices be incorporated into the calculation coordination methodologies. The existing standards on TRC and CBM are also proposed to be revised to require crisp and clear documentation of the calculation of TRM and CBM and make various components of the methodology mandatory so that there is more consistency across methodologies. Such changes will enhance the reliable use of the transmission system without needlessly limiting commercial activity.

NERC recognizes that the goal of achieving consistency may not mean that a single ATC methodology is required. With a limited number of methodologies, consistency can be achieved if the requirements of those methodologies are properly coordinated and communicated. The NERC Drafting Team, which I'm currently facilitating, is currently working with three methodologies. The first one is referred to as the rating system path methodology for ATC and TTC. We have a network response methodology under consideration for ATC and TTC. And the third one is the network response methodology for AFC.

A great deal of progress has been made since the proposed standards were approved for development by the NERC Standard Committee in February, which were to address the recommendations made by the long-term AFC-ATC Taskforce. However, a significant amount of work remains to complete the revisions to the standards. NERC has established an aggressive schedule of meetings for drafting, which will be coordinated NAESB since NERC would like to finalize its revised standards for submittal to the Commission for the Summer of 2007.

NERC and the electric industry are giving high priority to these standard revisions consistent with the entire spectrum of standards development activities that are currently underway, especially those standard initiatives that have been undertaken in response to the August 2003 blackout.

Just as a point of clarification, when we talk about network response, that refers to a method of calculating transfer capability for transmission networks where customer demand, generation sources and transmission sources are closely interconnected.

MR. HEDBERG: One minute, sir.

MR. LOHRMAN: Thank you.

The rating system path method is a method of calculating transfer capacity for transmission networks with critical transmission paths between areas of the network have been identified and rated as to their achievable transfer load capabilities for a range of system conditions. Generally, the rated system path method is used in the West and the two types of network response methodologies are used in the East.

With that, I'll conclude my remarks. Thank you.

CHAIRMAN KELLIHER: Thank you, Mr. Lohrman.

All the panelists should be aware, remember what I said this morning that your statements are in the record in full and the use the time to emphasize, punctuate and summarize -- and that's no criticism to Mr. Lohrman because he did excellent in terms of time.

(Laughter.)

CHAIRMAN KELLIHER: I just thought I'd repeat that.

Next is Mr. Ron Mucci, Williams Power Company on behalf of North American Energy Standards Board. Mr. Mucci.

MR. MUCCI: Thank you and I would like to remind I'm speaking for NAESB, not Williams even though I do see Williams on there. I will have to refrain from individual company comments and represent NAESB, the organization.

I'd like to say thank you to the Commission for providing NAESB with this opportunity to participate in the 888 reform process and we applaud your efforts to increase transparency and clarity to the underlying business processes and practices that will enable non-discriminatory open access transmission.

I would like to begin by framing the respective roles, which I think are critical as a back drop. First and foremost, the Commission, which is responsible for the policy and requirements. They are going to be essential that they be laid out. NERC, which as previously discussed, does reliability and NAESB does the accompanying business practice standards. And through our WEQ, which is Wholesale Electric Quadrant, which is comprised of five segments representing end users, LSEs, transmission, generation and marketeers and I might add a potential six segment representing independent grid operators. NAESB has built the structure and process in place to develop the necessary business practice standards. However, even with the right processes and structure in place, NAESB's ultimate success in meeting the Commission's objectives will depend on a few key factors.

First is clarity. Clarity from the Commission in terms of both policy and expectation. Second is engagement on the part of industry participants and the NAESB standard-setting process, and third is collaboration and coordination with other organizations, such as NERC, to ensure a seamless linkage between reliability and business practice standards.

Now focusing on ATC or we would say more appropriately TTC and the apparent lack of transparency and potential for discriminatory practices, the challenge from the NAESB perspective are rooted in two fundamental issues. The first is the methodology employed and result and models used to calculate TTC and ATC that has a direct impact on reliability.

The second area is the assumptions used in the models in terms of inputs, operating parameters and timeliness and availability of results. In terms of the former, NERC is clearly leading the effort to standardize the ATC calculations. Therefore, ultimately whether there's one industry-wise methodology, standardization of constituent inputs and component capabilities, commonality of calculation techniques or regional difference that will be determined through the NERC process. In terms of NAESB, as pointed out, we have begun and underway companion business practice standards, which will ducktail with and support the reliability components.

In order to facilitate the timely development of these standards, we request that the Commission provide clarity around their expectations and address policy issues up front rather than leaving the subject to potentially endless debate and fruitless effort to develop standards. And you have to understand NAESB, basically, in that process of mapping out those business practice standards looks at the data, the record layouts, posting requirements, who's responsible for posting what information with the ultimate objective of streamlining those processes and added needed transparency.

So with th at in mind, where clarity and guidance would benefit our processes, some examples around ATC at this point is there ambiguity and a broad spectrum of opinions regarding the specific data and associated posting requirements, which I could boil down to essentially issues related to what I call triggers and transparencies. For example, triggers refers to when and under what circumstances ATC should be recalculated. Without clarity, NAESB could be caught in endless debate deciding such issues as is it posted only on constrained elements in paths or all posted paths? Is ATC recalculated when requests for transmission services are evaluated or confirmed transactions are impacted? Or is it when a certain threshold has been met? Is there an impact in threshold tests with regard to ATC recalculation and posting requirements? And there is a diversity of opinions exactly when and what triggers the need for those calculations.

Regarding transparency, the issues that will be debated or could be debated include how often and what type of information should be contained in the required after-the-fact narrative postings? Do the postings apply to ATC changes in day ahead real time as well as planning studies, acknowledgement of a planning study as opposed to detailed assumptions and results of the study being posted? So I can go on with other examples, but clearly what we need is the clarity around those triggering events and transparency requirements.

So ultimately, it's difficult at best to develop the business practice standards necessary to support the Commission's goal of transparency when the requirements, as expressed to date NOPR are opaque to some and clear to others or subject to broad interpretation in between. We need policy direction around areas such as confidentiality in the context of disclosure requirements, frequency of when information should be updated and posted, burden of compliance, commonality of methodology versus regional difference.

MR. HEDBERG: Mr. Mucci, could you please conclude your remarks.

MR. MUCCI: In summary, the key elements for success of policy guidance from the Commission is clarity around granularity, type of data and frequency, broad and active participation in the NAESB process, collaboration to meet clear objectives and defined time lines. So the guiding principle I'd like to leave you with is FERC does policy and requirements. NERC does reliability and NAESB does business practice standards. Thank you.

CHAIRMAN KELLIHER: Thank you.

Now we'll hear from MR. Steve Naumann, Vice President, Wholesale Market Development, Exelon Corporation. And as I mentioned earlier to you, our former colleague, Commissioner Brownell, is a big fan of yours. If she were still with the Commission, she would be very happy to see you today as are we.

MR. NAUMANN: Thank you, Chairman Kelliher and Commissioners. Exelon appreciates the opportunity to speak here. We've added enough paper to the 5000 some odd pages of comments and I won't repeat what we just put it. I'd like to hit a couple of highlights. But first I'd like to give you a little bit of background.

Exelon includes two separate transmission owners, ComEd serving Chicago, PECO serving the Philadelphia area. PECO has been a long-time member of PJM. ComEd is a newer member of PJM. The reason I raise that is up until 2004 when ComEd became part of PJM and had PJM take over the ATC and the OASIS functions, ComE, as a transmission provider did these things. So we've seen this both from being in an RTO and from having to do this ourselves as well as our affiliate, Exelon Generation, as a customers. So we're kind of coming from all three sides, if there can be three sides.

Just to hit some of the highlights. On the challenges, we believe that those doing the ATC calculation must be prepared to change their methodology to conform to what comes out of the NERC process, must be going to best practices and we can't be hung up on "My method is best and I don't want to change." Engineers have real, honest differences of opinion and it may be that both sides are right or neither side are right, but we've got to come an answer. We just can't sit there. Definitions have to be consistent and when someone says TRM it has to mean the same thing. It can't mean different things to different people.

Timeline, in our comments we had said there needs to be a deadline. We had thought it might take up to one year. We're gratified to hear that NERC is on a schedule prior to this summer. CBM and TRM, we think one of the keys is that those factors need to be used in the same manner for all purposes, whether for granting transmission service to third parties or whether for expanding the system for one's own network load. If you need CMB, you need CMB -- both cases. If you don't for one case, we don't understand how you can need it for another. So there needs to be consistency.

On the information to be transparent, we think there do have to be narratives and we understand the burden. Sometimes there are many small changes in the system that make a small change in ATC and it's difficult to isolate. But there are a lot of big changes that people know about and there's nothing more frustrating for a merchant to ask "Why was I turned down" and the answer to come back "No ATC." Believe me, that has been the most prevalent answer. That honestly doesn't mean anything. You were turned down for no ATC because there's no ATC. So there needs to be better post sticks.

And as far as some of the other stuff, we believe that the designation and undesignation of network resources needs to be done on the OASIS. It needs to be done under the same rules as the granting of any other transmission service. We think it's a matter of confidence in the system that all the users are subject to the same analysis and someone can see that none one has jumped ahead of them, other than because it's a higher priority request.

MR. HEDBERG: One minute, sir.

MR. NAUMANN: I've written some of the metrics. We do think that having metrics summarized is important for market participants because, if you get thousands of pieces of data, the human mind really can't absorb. If it's summarized, it's a lot easier.

So again, thank you very much. I'm hear to answer questions and look forward to it. Thank you.

CHAIRMAN KELLIHER: Thank you very much.

Now we'll hear from Michael Smith, Vice President, Regulatory and Legislative Affairs with Constellation Energy Commodities Group.

MR. SMITH: Thank you, Mr. Chairman, Commissioners.

I will attempt to be very brief in my opening comments today. Mostly because I'm scared to death of Dan.

(Laughter.)

MR. SMITH: Avoid the wrath.

Constellation really appreciates the opportunity to be here today. In order to put my comments in context, I'd like to explain just a little bit about Constellation. We have as our operating affiliates a merchant generating company, a wholesale power marketer, a retail marketer that's nationwide and a transmission owner. So we see a lot of sides of this issue. We don't see all of the sides of this issue, but we see an awful lot of them and our comments in this docket are informed by that.

No surprise that we fully support the Commission's efforts to increase the transparency and consistency of ATC calculations in the OATT. However, we'd like to flip around the order here and we'd like to suggest to the Commission that focus first on the transparency aspects while consistency is being worked out in the NERC and NAESB process that we also support. That's important because transparency really goes to the core of why we're here in the first place, which is this perception of undue discrimination in the provision of transmission service.

If transmission providers give transparency in the ATC calculations to their customers, that will go an awful long way toward getting rid of this perception of discrimination that continues to linger under the OATT.

That perception of discrimination can truly chill commercial markets in these areas. If transmission customers don't believe they're going to get a fair shake or are at an informational disadvantage, they may not be willing to go try and serve customers in these areas. So really go a long way toward improving that perception.

Also, increased transparency is efficient for both the transmission customer and the transmission provider. If I, as a transmission customer, can't replicate with a reasonable degree of certainty the transmission providers is ATC calculations, I can target my requests to paths that I think are going to be granted and we'll stop having this crazy interactive process that Steve described where I want ATC. Well, you can't have it. Why not? There's not ATC. Well, why not? And we go through this time and time again, where that transparency will be much more efficient. That will help both transmission providers and transmission customers.

The provision of this data, we believe, should be an interactive process. By the way, we have provided in our comments a fairly extensive list of the types of data we, as a transmission customer, would like to see. That's appended to the written comments that are filed for today as well. If the Commission is inclined to require that type of transparency, we would suggest that fairly soon after the final order, transmission providers and customers need to discuss, be required to meet to discuss the protocols, the timing by which this information will be provided to transmission customers and then have some periodic follow-up and in a stakeholder type process, it maybe could even be part of the regional planning process to ensure that the data is flowing on a useful basis. This is stuff that we can actually use.

I'd like to take one brief aside. We have had in this case a lot of filings advocating some type of open and transparent security constraint economic dispatch. Constellation supports going down that road and looking very carefully at that particular idea of transparent redispatch cost in real time. We confined our comments in this NOPR to the framework that the Commission set out in the NOPR, but would certainly encourage the Commission to undertake a review of these issues at an appropriate time, either in the context of this case or in a separate proceeding.

Moving on to consistency, again, we support the NERC/NAESB process. We do have a concern that six months is awful fast. We'd like to see the timeline for having something done be set at a firm time period, possibly a year, but with staff review and oversight into the process to make sure that progress is actually being made, perhaps, requiring the process report out to the Commission quarterly on how its going in terms of getting this consistency as best as it can be, given the circumstances between the various transmission providers.

In summary, let me just conclude by observing that when the final rule comes out that's going to be the end of the beginning and we're not going to get this 100 percent right the first time and the process of improving ATC calculation under the OATT really needs to be an iterative process between the Commission, it's staff, the transmission providers and the transmission customers. If we do that, I think we have a real good opportunity to provide some real benefits to end use customers.

Thank you and I look forward to having a further dialogue.

CHAIRMAN KELLIHER: Thank you, Mr. Smith.

Next we'll hear from Edward N. Henery, Director of Reliability, American Public Power Association.

Mr. Henery.

MR. HENERY: Good afternoon, ladies and gentlemen.

I'm Nick Henery, Director of Compliance, Standards and Reliability for the American Public Power Association. The North American Electric Reliability Council's guidance document dated 1996 entitled Available Transfer Capability Definitions of Determinations requires that the calculation of ATC recognize the necessity of determining ATC values using a regional or wide area coordination to capture the interactions of the electric power floats. Unfortunately, the current reality of that concept of wide area coordination was never quite realized. The various components that are required to determine ATC are established used procedures based upon the regional reliability organization study methods, transmission service business practices or company goals to meet the needs of the market within each of the interconnections.

The accuracy and the dependability of ATC calculations are only as good as the accuracy and dependability of the components of the ATC formula. These are, of course, the total transfer capability, the existing transmission commitment, the capacity benefit margin and the transmission reserve margins. The first component of the ATC formula is the transfer capability or what was called TTC. Under the NERC functional model, the transmission planner is the reliability function tasked with calculating the TTC for long-term transmission planning. For short-term transmission planning or operation planning, the operation planners, which is a part of the transmission operator function, calculates the TTC.

The TTC in all cases is a prediction by the transmission planner or by the transmission operator of the reliability limit or the total capability of a path, a system or a flow gate for a particular period of time. The accuracy and dependability of the ATC calculation can be no better than the accuracy and the dependability of the TTC values calculated by the transmission planner or the transmission operator. However, accurate TTC values are very important to the reliable transmission planning and real time operation of the bulk electric system.

In the Eastern interconnect where multiple regional reliability organizations exist, a collective organization comprised of representatives from each of these groups could establish the long-term planning and operational planning rules for the interconnection. This type of planning program would go a long ways towards producing TTC values using consistent and transparent study assumptions and would minimize seams issues throughout the entire interconnection.

The second component of the ATC formula is existing transmission commitments or ETC. The rules for determining and using ETC components of the ATC formula are developed and applied at the individual utility level within the RRO. The different methods or rules by which transmission customers reserve transmission capacity with an individual utility and then schedule the energy over that reserve transmission capacity will often result in different

ATC values for each transmission service provider in the same path.

This can occur because one transmission service provider will have a rule of decrementing requested transmission capacity from ATC while the other transmission service provider will not decrement the ATC until the transmission capacity has been confirmed as reserved and the energy has been scheduled on the reserve transmission capacity. This is one of those areas where the regional business practice and rules, transmission tariffs or business objectives can and often do clash with reliability rules.

MR. HEDBERG: One minute, sir.

MR. HENERY: The electric utility industry has been trying for about a decade to determine that the market rules will define the boundaries of the reliability operation of the bulk electric system or whether the reliability rules will define the boundaries of the market. A more fundamental level, transmission service providers and transmission operators often make different assumptions and use different methods to account for the current and future transmission needs of load-serving entities serving bundled retail loads and load-serving entities using wholesale transmission service.

Additional industry work is needed to ensure these assumptions and adjustments are relatively consist and transparent to all affected parties within the interconnection. The rules for calculating capacity benefit margin and transmission reserve margins are also determined at the individual utility level. The use of these two values in the ATC formula presently can result in ATC values that have questionable or dependable accuracy.

MR. HEDBERG: Sir, your five minutes are up, if you could conclude your remarks, please.

MR. HENERY: In closing, there are two points I want to get across. First, the ATC value must be calculated using an open transmission process and must be as consistent as possible within an interconnection, given say, such as network topology.

Second, the best way to achieve this is to have reliability standards, not commercial tariffs, require this consistency and openness. Now I have attached my written remarks answers to the questions you ask in the conference notice and I will be happy to address those responses during the Questions & Answer period. Thank you for giving me the opportunity to speak today.

CHAIRMAN KELLIHER: Thank you, sir.

Next is Mr. Jerry Smith, the Reliance Partnership Manager, Arizona Public Service.

MR. SMITH: I'd like to start by thanking the

Commission and its staff for proceeding with this technical conference. I think it gives APS and the West a chance to brag a little bit because I think what we're doing out west is sort of what you're looking for in the NOPR. Some of my recent work efforts have been with NERC, NAESB, WEC and the West Connect efforts. APS belies that the standards should be developed in these arenas. APS fully supports the Commission's goal to developing transparent and consistent standards for determining ATC and the components that make up ATC.

APS, together with other transmission providers in the West, is determining its transfer capabilities in an open and transparent process in accordance with established and published standards. We ask that the Commission file a rule to recognize this fact and allow the process to continue.

In the West transmission transfer capabilities are determined based on the rated path methodology. As Bill mentioned earlier, we use a rated path methodology. That's the transfer capability. The ATC we've developed is done in accordance with WECC determination of available transmission capability within the western interconnection of published standards. The determination of ATC compares within the determined studies of the past transfer capability.

The determination of ATC for path begins with a determination of the path's transfer capability. In WEC, transfer capability is determined prior to a new line being brought into service or when modification to the line affects the TTC. Or rack of rated path, TTC is determined in a three-phased process. It's first submitting the project to WEC. Second, assessing the project affects; the third, review and approval by not only the affected utilities, the appropriate WEC committees, but the WEC board of directors.

WEC reviews the rate of paths prior to the summer and winter seasons to determine transfer capabilities of the paths. That becomes the paths TTC for the season. Non-rated paths that affect subregions use the same process, however, neither WEC staff nor the board of directors have to approve these. Under WEC, there is no single process for calculating TTC for the path's internal to a single transmission owner.

Within West Connect, a transfer capability process, all assumptions, calculations, and methodologies used in the path ratings are posted, including those internal to a transmission provider's system. They are presented to the stakeholders for review. The TTC calculations then remained fixed and change only if there is a physical or operational change to the transmission system. The determination of ATC then becomes a simple math equation. The components of the equation are determined using the WEC ATC determination standard. Through the West Connect transfer capability process, the West Connect members have agreed upon the elements that will go into determining each of the ATC components. The agreed upon elements are then set in the OASIS, the common OASIS for West Connect and can only be changed by the OASIS vendor. They will only be changed upon a written notice from the transmission provider to the vendor. The transmission provider will then post notice on its OASIS as to what the changes were and why the changes were made so that customer or the transmission customer can see why these changes were made and what affects they had on the ATC.

We believe this satisfies the NOPR stated policy and objectives, but recognizes that some of the components of ATC may require further review to more clearly determine what makes up the components and I know that NERC and WEC are both working to better define that.

APS supports the Commission's efforts to increase the transparency of ATC calculation and we believe that all of the elements that go into the determination of ATC components should be transparent. That includes network agreements, grandfather agreements and curtailments. APS supports working through NAESB to develop the ATC business standard, especially the standards and communications protocols and we ask that the Commission's rules provide the transmission providers and their OASIS vendors adequate time to make the modification.

Since I've got 27 seconds left, I'd just like to thank you for your attention and I appreciate your allowing me the opportunity to present APS's position on this topic.

CHAIRMAN KELLIHER: Thank you, Mr. Smith.

I just want to remind the staff that they're free to ask questions. This is probably an area where I'm sure you're more familiar with the record than we are. It's kind of a difficult area for at least a non-engineer like me to wade through. But let me start with a couple of questions and then colleagues can join in and staff as well.

First of all, with respect to NERC, your projection that by next summer you would have finalized three methodologies, perhaps?

MR. LOHRMAN: Yes. We realize that's a very aggressive schedule. A lot of it depends on how the NERC standard process goes. As you're aware, they have a procedure for posting, commenting, posting, commenting, balloting. If the industry is able to get together and come to a consensus and do that without an excessive number repostings and recommenting, that could be achievable.

CHAIRMAN KELLIHER: So you're using your ANSI process?

MR. LOHRMAN: Yes.

CHAIRMAN KELLIHER: Are you using the emergency ANSI processes?

MR. LOHRMAN: No, it's the regular process.

CHAIRMAN KELLIHER: In the case of developing the methodologies, would you be developing standard definitions?

MR. LOHRMAN: We're working at looking at standard definitions, standard posting criteria, looking at coordination requirements, looking at issues of dealing with what types of assumptions should be made, how the standard would interact with the planning criteria and the operating criteria. We're also looking at considering the issues of what the data elements would be themselves.

CHAIRMAN KELLIHER: When you say "looking at the standard definitions," the end result would be a standard definition?

MR. LOHRMAN: Yes.

CHAIRMAN KELLIHER: You're not asking the question should there be a standard definition. You're grappling with what the standard definition should be.

MR. LOHRMAN: That's correct.

CHAIRMAN KELLIHER: Because I thought Mr. Naumann's statement -- most of the key terms in the laws we administer are defined in statute, otherwise we define them by regulation and the meaning is consistent. I find illusive what the rationale would be for non-standardized definitions. I could see how we might want to have more than one methodology at the end of the day for ATC calculation, but I don't know why, as you said, CPM would mean one thing in one part of the country and something else in another part of the country.

MR. LOHRMAN: I think we would agree that standard definitions is the end goal. The issue of having different definitions in different areas of the country is a matter of practice and how the different markets and different regions developed.

CHAIRMAN KELLIHER: Is there anyone who is offended at the notion of having three approved methodologies, perhaps?

Mr. Naumann?

MR. NAUMANN: We could live with two.

(Laughter.)

MR. NAUMANN: We understand the difference between the eastern interconnect and the western interconnection. We've thought about this and we've actually had to deal with this when ComEd was part of Maine, the former Reliability Council, and we just don't see that there needs to be a different methodology for those who use ATC and those who use AFC. That there needs to be one methodology and then a conversion from AFC numbers to ATC numbers. Now if the only difference between the two methodologies is taking the AFC and adding a post-process, an additional process to converting that from AFC to ATC, then if you want to call that a separate methodology, we're fine with that. But the part that goes into those calculations, we don't see physically that there is any difference. It's still current flowing over transmission elements and all the pieces that go in -- the dispatch, the load models, how you handle transactions, what transactions get credited for counterflows. I could go on with a liney of things. All of those things should be treated identically regardless of whether you're an ATC calculator or an AFC calculator. So that's where we differ.

MR. LOHRMAN: I'd like just to point out that NERC is not wedded to three methodologies or one methodology. We'll work with whatever the industry and the Commission comes up. But I think being more involved in the standards drafting team, I think we're really headed in the direction that Steve is talking about. There are a few differences between the ATC and the AFC methodologies, but the ones that are similar would basically be the same.

CHAIRMAN KELLIHER: Mr. Smith?

MR. MICHAEL SMITH: I was going to add kind of as a guiding principle differences between the regions should be rational and explainable, and I personally have a hard time believing that differences in the core definitions of the ATC calculation can be rational or explainable. Now there may be methodologies that kind of come down below that that there could be a reasonable explanation as to why that should be different. But as you talk about the very core elements of this stuff, it seems to be that the consistency should be the absolute goal.

CHAIRMAN KELLIHER: Mr. Naumann?

MR. NAUMANN: I would almost like to see in a rule the rebuttable presumption. I mean we have said we don't understand why there should be regional differences within the eastern interconnection, but granting that there may be something about a system that I don't understand why it should be different, I think if the rule said the rebuttable presumption is no regional differences with an interconnection and then there has to be a physical reason for such a difference.

Let me give you an example. There is one region that says, well, if the impact is only 1 megawatt, even if a flow gate is overloaded, that's okay. I personally don't understand the purpose of that. I don't think that's a physical difference. I think 1 megawatt over a line makes the same overload, whether it's in the far western part of the eastern connection or in Florida or in New England. But what we ended up finding is that difference then gets exploited by people who put in multiple transactions each of which has less than 1 megawatt of impact and suddenly you now have 10 megawatts of impact overloading a facility and you have to deal with it in TLR. So that would be an example to me where there is no rational, physical explanation and a strong statement by the Commission against regional difference -- now I realize that's 180 degree turnaround what our 888 and 889 and I've talked to my boss about that -- p.s. my boss being Betsy Moeller.

(Laughter.)

MR. NAUMANN: At that time that was the right thing to do. We've now gained 10 years experience and we think the time is here to say this is not the time for 10 or 8 different flowers to bloom -- maybe two. Again, we understand the two, but let's go and get it right so that we have coordinated numbers and people have confidence that there aren't special rules for favoring people.

CHAIRMAN KELLIHER: Do you think the primary benefit of having a consistent methodology in an interconnection is the reduced prospect of undue discrimination in transmission service or is it also -- is there an efficiency benefit? Is the system used more efficiently? Is there a reliability benefit?

MR. NAUMANN: All of them, Chairman Kelliher.

Again, this example of the 1 megawatt -- we'll make an exception for 1 megawatt. Well, to me, that's both a reliability and a non-discrimination. So I can take any specific exception and I have to look at it and say, well, it does this or it does that. What they are -- and we understand these are holdovers from the way things have always been done and I'm not saying that -- you know, they were done and they were done well and the system was kept in tact. Or they are because a bunch of stakeholders got together in this region and came to some agreement sometimes which were trade offs -- well, give me this and I'll give you that. As I said 35 years ago in engineering school, we learned something about Kirkoff's Laws and the last time I looked they still are in place exactly the same within North America and that's why NERC should, through its process, say these things have to be defined in way. Everyone won't be happy because there will be differences of people of goodwill. Engineers think differently. By the way, at least you're not dealing with relay standards, then you would have a hundred different right ways of doing it. But everyone is going to have to get in a room and they're going to have to say we're going to agree to this because, in truth, and I'll leave this to Bill if he disagrees, the ATC calculation is not exact. Let's not fool ourselves that you're going to get it down to the last megawatt. There are errors in the data. There are errors in the calculation.

The system isn't exactly what you think it's going to be. So to try to get more preciseness in the calculation through fighting over some of these little, little pieces than you can really get, I think is putting form over substance. We have to get a number, a methodology that people say, first and foremost, will maintain the reliability. Second, will give non-discriminatory access and third, will give people the confidence that they are being treated comparably.

CHAIRMAN KELLIHER: I'm going to ask the panelists about some of what we've been discussing at FERC. Does everyone agree that the definitions should be uniform?

(Panel agrees.)

CHAIRMAN KELLIHER: Do people agree with Mr. Naumann that a methodology within an interconnection should be consistent?

Mr. Henery, no?

MR. HENERY: No.

MR. LOHRMAN: I think part of the discussion of whether or not a methodology is consistent goes to what the definition of the methodology is. It's sort of like when we say that word considering three methodologies, actually two of them -- network response methodology for ATC and network response methodology for AFC they're very similar. It's just that one exchanges AFC values and one exchanges ATC values and we would be working on a procedure for doing the translation between the two as Steve mentioned, so in effect, there might be two methodologies.

CHAIRMAN KELLIHER: Your point of view is they're the same methodology. There's just the translation.

MR. NAUMANN: If that's the difference in the methodology, then they are, in fact, the same methodology and we would agree with that direction. Yes.

CHAIRMAN KELLIHER: What's the status quo now in the eastern and western interconnection? How many different methodologies are used?

MR. JERRY SMITH: In the West right now there's one methodology used. However, California is looking at going to a flow basin. If that happens, there might wind up being two methodologies used and I believe as long as we get the definitions and the components defined right and we make how we do it very transparent and work with California and possibly some others in the Northwest that are also looking at that, I think that we can come up with a workable solution and maybe evolve to something that's even more efficient than either one of these two methodologies. So I have some concerns if we try to lock it down to one methodology and don't try to allow the flexibility to move forward a little bit.

CHAIRMAN KELLIHER: I'm going to refrain and turn to my colleagues and ask them to join in.

COMMISSIONER SPITZER: Thank you.

Mr. Chairman, just to follow-up on your question regarding the scope of the status quo, I'd ask you to indulge me a little bit because it's certainly helpful to understand where we are now and I'm am the only lawyer in my family. We've got a lot of engineers. They profess exact objective certitude in their profession, so I guess I'm reassured Mr. Naumann that there's not in the engineering profession, but we've got --

CHAIRMAN KELLIHER: Their laws don't get amended.

(Laughter.)

MR. NAUMANN: I am both an engineer and an attorney.

COMMISSIONER SPITZER: I understand that, yes. So I see from your resume. In terms of the scope of the current circumstances, you've got four different variables that are components or at least three methodologies so that the uninitiated you take four squared multiplied times three. Do we have 48? I guess I'm trying to ascertain the scope of the current problem or divergence among the centers.

MR. NAUMANN: Commissioner, I guess it comes down to what you mean by methodology?

COMMISSIONER SPITZER: Mr. Lohrman's identified three methodologies.

MR. NAUMANN: You could have the same methodology and yet -- and this is going to be drilling down really into the weeds -- but if, for example, one transmission provider applies TRM, which is transmission reliability margin.

COMMISSIONER SPITZER: That's one of the variables. That's one of the four variables, is it not?

MR. NAUMANN: There are more than four variables is what I'm trying to say. There's how the dispatch is done. There is how the ETCs, the existing transmission commitments, are modeled. There are how counterflows are taken into account. There are some transmission providers that said, well, if a long-term firm transaction provides a counterflow, well, then I'll put that in the model because that relieves the overload. There are others that say, well, I can't count on that occurring on that hottest day, therefore, I'm going to take the conservative approach and I'm not going to put it in the model. That creates completely different answers and so what I'm saying is there are more than four variables, Commissioner.

COMMISSIONER SPITZER: And there are subvariables and it seems to me until we isolate or standardize the definitions of those variables and subvariables it doesn't matter how many methodologies you use. You're going to continue to have disparate results.

MR. NAUMANN: Absolutely.

MR. LOHRMAN: One of the important aspects for consistency, as Steve was alluding to, is making sure that not only are the definitions consistent, but the way that you apply those definitions to the data and the way the data are incorporated into the model is consistent from timing perspective, from a use perspective and from the interaction across seams as well.

COMMISSIONER SPITZER: Are there engineering or reliability reasons why distinct should remain or will remain with in these variables or subvariable? In other words, is there some necessary engineering criteria or demands that are contrary to efforts to standardize?

MR. NAUMANN: In my opinion, many of these issues are matters of judgment, of engineering judgment. The counterflow issue I mentioned there is no 100 percent answer that an engineer can give you that all counterflows must be modeled or no counterflows should be modeled. But leaving that decision to -- I don't know how many transmission providers -- ATC calculators we have in North America right now -- but leaving that decision up to that many people to do it the way they want undermines consistency and from a merchant's point of view -- I'll let Michael speak more to it -- I believe undermines confidence.

You get everybody in the room and you come up, through NERC, with a methodology. How are you going to model counterflows? What are the specific elements that go into TRM? What are the specific elements that go into CBM? To which models do CBM get applied? Yes, there will be disagreements, but if everyone understands they have to come to an agreement, I believe it will be done. That's what you all did prior to Order 888. You set up a What team and an How Team. You told the people go there and do it, and a bunch of us went down to Dallas and we were the What Team and we said we're never going to do this and we did. I think you need to get the engineers in the room and say we will come up with an answer.

CHAIRMAN KELLIHER: Mr. Smith, is the -- Arizona Mr. Smith. How is that? In the path system, does that somehow mitigate or reduce the number of judgment discrepancies that occur or do you have the same phenomenon?

MR. JERRY SMITH: I think until we have a common definition of the elements that go into each of the components of the ATC calculation, I think we're going to have a lot of judgmental calls and that's one of the reason I felt that we needed a good definition of the terms and how they're applied similar to what Steve had sort of implied. So I think in the West right now -- we and the West Connect footprint have defined what we think should go into each of these components. We've set it and put it in our OASIS, so we have a standard there, but I'm not so sure that our standard is right when you go looking at the rest of the West. And until we come up with a common language, an understanding of the common terms and how they're applied, we need that. All of us need that.

COMMISSIONER SPITZER: Thank you, Mr. Chairman.

COMMISSIONER KELLY: When you get finished standardizing as much as you can standardize, will you be able to give us a standard deviation?

(No response.)

COMMISSIONER KELLY: No. Engineers can always do a standard deviation, can't they? That was a real question.

(Laughter.)

MR. LOHRMAN: I'm not sure I understand your question, but are you talking about perhaps the differences.

CHAIRMAN KELLIHER: It's something like Mr. Naumann was saying that it's not precise in the end. So we're curious as to how imprecise might it be I suppose.

COMMISSIONER KELLY: Are you going to be able to give us a plus or minus? Are we going to have degrees of confidence or bounds? When we finish all this are we going to have a good --

MR. NAUMANN: That's a good question, Commissioner Kelly. I haven't thought about it all that much or at all until now.

(Laughter.)

MR. NAUMANN: I would say that, for example, one thing that could be done is where there are different ways of doing something. Now, for example, the dispatch in the case to come up with the TCC, one could say, well, if we use method A and run through a whole bunch of calculations. Then use method B and run through a whole bunch of calculations, you could get some level of deviation. It may not be a standard deviation by the mathematical definition, but I believe that would be one way by taking the different methodologies and seeing the outcomes that you could see how much the outcomes would actually vary, the complexity, just to say is -- the answer may well depend is that, on the whole, that deviation might be small, but on a very specific element right near the generator it could be awful large and that's why the topology matters. Maybe that's something for NERC and some of us to think about some more in our comments.

COMMISSIONER KELLY: It sort of gets to the point that Mr. Smith made, I think, that in the short run and maybe in the long run the best thing is to make it transparent then we know where the differences lie.

MR. MICHAEL SMITH: That will help tremendous in order to facilitate further commercial transactions for the benefit of end users in the short run, we'll take various methodologies. As long as they're transparent, we can kind of see what's going on there. Then we can drive down to making them as consistent as possible to reducing the noise to a tolerable level. At that point then, if those differences are rational and explainable, that's fine. But the transparency then kind of helps you through your standard deviation problem because at least then we can see in each case that there's a difference how it works in that particular case. We can model it.

MR. MICHAEL SMITH: Can I recognize a colleague in the audience, Steve Goeff from the Missouri Commission is back there and I just wanted to say how impressed I am that you're hear listening to our ATC methodology discussion.

(Laughter.)

MR. MICHAEL SMITH: That speaks very highly of you. So thanks for being here.

COMMISSIONER MOELLER: Thank you, Mr. Chairman.

Just to follow up on Commissioner Kelly, what are the barriers then for making those calculations transparent?

MR. JERRY SMITH: We have none, in that right now we had -- our calculations fairly transparent, but we went to a common vendor and when we went to the common vendor, the standards and communications protocols that were established did not require them to be out on the OASIS and at that point the vendor took it off the OASIS. But we were working with our own OASIS that we developed internally that was there. So we have no trouble with putting them out transparent.

And back to your question, Commissioner Kelly, because I believe that, in the West when we stick with the rated system path, we will come up with the same number all the time so long as we have the same definitions. But the rated system path is not based on -- it's not as dynamic as the flow base situation is on the East. So I think we would stay fairly consistent. So I don't think there would be a huge deviation there.

MR. NAUMANN: Commissioner Moeller, I don't think there are any barriers to making it transparent. I do think there are practical barriers to making all the transparency useful. Some of the things that go into calculations take a whole lot of expertise and it's really local expertise. Somebody mentioned earlier this morning, in the planning session, operating guides, special protection schemes, really understanding how things like those are used and when they're used and how they fit into the ATC takes a lot of time to understand. I'm not saying it's not understandable, but from a commercial point of view it may be very difficult to get enough people who have those kind of qualifications, put the time in to understand it to turn that around to make it useful.

MR. HENERY: The only thing I would like to say in regard to the question about how accurate things will be, keep in mind these are forecasts much like a weather forecast in a way. I think the thing that the Commission's got to realize is, is that the methodologies that had been developed over the years to what people say is calculation ATC really came out of the reliability side of the business when they were calculating -- when the planners calculate the TTC and when the planning operators calculate the ATC. The physical characteristics of the transmission system often dictate utilizing one method versus the other.

Steve's absolutely right in the sense that Ohm's Law hasn't changed. Actually, if you understand how those calculations are made, you will see that they're basically calculating in the same way. It's just the way the planners articulate am I going to articulate it as an entire system? Am I going to articulate it as a particular path or am I going to get real granular and get down to a particular substation? That's all that's happening there when you say that.

The problem that exists is like as has been pointed out here. Some engineers, to maintain reliability, will put a belt on it and then put suspenders on it and some will even put the safety pins in and that system's not going to go down. And as a consequence, they have a tendency to remove a lot of facilities out of the system to ensure that if something happened they can go get it to keep the system up.

What would be very beneficial, and I think NERC is moving in the right direction with this standard drafting team that they have got in doing this is that they're really requiring that the TTCs out here have, within an interconnection, that level of consistencies, the rules for planning. As long as there's a consistent rule for planning it will work.

The ETCs is going to be a little more difficult and this is where we're going to have to work with NAESB an awful lot on that because there are some business rules and reliability rules that can clash in here and we've got to make sure that those don't happen. As far as CBM and TRM, those two are pretty much kind of engineering numbers that TRM is -- if you look at a large TRM, it's telling you that the transmission planner doesn't have a lot of faith in his TTC and he's holding out a lot of stuff because he thinks that maybe his load forecast are off or something like this. So as long as we've got the same rules to calculate that throughout, then that's going to remove a lot of Mike's problems here about, oops, are they telling me the truth?

MR. MUCCI: I'd like to add on. While NAESB certainly doesn't take an advocacy position as to whether there is one method or multiple methods, but Commission

Kelly you raised a point about transparency and I want to say that it can't just stop at the modeling. That you have to flow it through to the business practice standards and it gets back to the issues that I made in my comments. We've heard debates, at least to this point, is when ATC changes is it by this much? Is it every time it changes? When should it be posted? Is it on OASIS or some have suggested, well, what if it's just a website and those who go back far enough will remember EBBs? I mean do you want a consistent format for that information? And someone else made a very salient point. Data is not necessarily information and so how it's laid out, is it retrievable? Can you do something with it? I mean all those issues get around the business processes that ultimately flow from what has been discussed on the panel around the engineering and modeling side. So I just want to say that transparency needs to flow all the way through so that basically users of the transmission systems can take that information and be able to hopefully define some of the issues around what gave rise to? What were the assumptions made? Why did the results come up this way? And that helps, I think, bring credibility to the process. So I just want to say we stand ready to develop the business practice standards and I think they're essential in order to bring that piece of transparency that's ultimately needed for the marketplace.

MR. LOHRMAN: I'd just like to say that NERC's drafting team is looking at that and is working on that from a perspective of consistency in definitions, from a first consistency in the application of the assumptions, of the synchronization between the planning and operating criteria and planning and operating horizons as well as looking at how the individual transmission service providers would coordinate with neighboring or adjacent TSPs as well. That's a critical component of this is making sure that, even if folks have the same definitions, the same data and the same assumptions, that they're using them on a coordinated bases so that they're in sync when they do the ATC or the AFC calculation.

CHAIRMAN KELLIHER: Kathleen?

MS. BARRON: I wanted to follow up on something Mr. Mucci said about the NAESB standards development process. It seemed to me like you came here with a number of questions and you're looking for more clarity from the Commission, and I'm wondering if that reflects some discord or some difficulty in the standard development process because obviously there's a tension in the proposed rule between the Commission from Washington deciding how those issues are going to be resolved as opposed to, as Mr. Naumann suggested, putting the people who know better in a room and having them come up with something. So I'm wonder if the rest of the panel agrees that you'd like the Commission to be more clear and more prescriptive or whether instead these industry groups and the standard development process can do the job?

MR. MUCCI: I'd like to reply to that. First of all, as far as the standard-setting process itself within NAESB, it is a voluntary, consensus-driven process. So I want to say that up front.

In recognizing that, and actually I think that's an attribute -- and it is an ANSI approved process and organization -- that at the end of the day what I've suggested we need guidance on is were there are policy-related decisions. And quite frankly, if there something that you want to see in a certain way, say it as opposed to leaving it unsaid and then subject to debate. I clearly understand where you're going. The question is to what degree do you micromanage the process and get down into the weeds and as it relates to the business practices to support those, we certainly stand ready to do that. But to the greatest extent that the policy issues can be resolved and as much clarity as to what you're looking for can be expressly stated that's going to benefit us because I can only say by experience because I sat for almost a year on Energy Day and you can sit in these meetings -- and again, I'm not wearing the Williams hat for a minute -- yes, it's speaking both for Southern Energy and Williams and all those spectrums, but you get a very diverse -- and that's the strength of the organization -- but a very diverse group and you can imagine that there's going to be -- if latitude is granted to a large degree, then you're going to be all over the place and that's a very inefficient way to go about setting the standard. So we can do them, but we are asking for guidance and policy direction.

CHAIRMAN KELLIHER: Which areas do you think there's the greatest need for policy direction?

MR. MUCCI: I highlighted two events. I think there's a lot of debate as to when do you do it. Is it when ATC changes by what? How often? In reading the NOPR and they talked about the 10 percent rule, it seemed to me it was applying towards planning, when you're doing ATC for planning purposes. But when you're down into real time and ATC changes, I think there are some who are very concerned that that could be almost an insurmountable amount of data -- not information, data. And so I think there is need to get clarity around what events drive the need. Is it every time these calculations are performed? Is it ATC and system values or only on the specific elements? It's those things? Where do you believe the information needs to be illuminated in order to achieve the goal of transparency. And then I mentioned some posting requirements because, in the end, a good example was on the narrative and I've at least have heard some view that when a planning study is done that the narrative simply needs to be an acknowledgement that a study was done as opposed to, okay, and what did it say? In other words, what assumptions were in those studies, what modeling pieces and what were the results and is it a push/pull model? In other words, is it up to the market participant to go out and find it somewhere, request it? Or do you expect that when a planning study is done, whatever the timeframe, whether that be operational or longer term planning ATC, TTC and all the other elements without repeating a liney of the alphabet soup, when do you expect that to be posted and how should that be made available? It's those kinds of macro questions -- and again, we will follow-up with written comments -- so recognizing the limited time, but I thought I would give you a couple fairly large examples of where policy guidance and direction would certainly make this a more efficient process to develop the business practice standards.

CHAIRMAN KELLIHER: That's a very helpful point. I appreciate that.

Dan, Kathleen, any other questions?

MR. HEGERIE: I have one question. Mr. Naumann brought up the fact that network resources ought to be on the OASIS as well to make a complete picture as to what's going on. Were you referring to resources to serve native load as well or was it just network services or is this point-to-point?

MR. NAUMANN: All network resources. The last I looked you actually -- I don't know if it's Section 26. I've been out of this for a while. There's one section in the current LATT that basically says you have to have a book where you keep all this stuff. Of course, a book doesn't do other people much good. I think all requests for new network resources have to go on the OASIS and when you undesignate and I don't think that's too much of a burden, but to me it seems the only way to bring confidence that all uses of the transmission system are being considered in the same way.

MR. HEGERIE: Do you we get push back at all from anyone saying that that's like putting native load on the tariff if we do that. Or do you see that as a separate issue?

MR. NAUMANN: I don't think that puts network load on the tariff. It's simply saying that when you evaluate your uses of the transmission system you have to evaluate the uses of the transmission system for everybody in the same manner. I mean it's a takeback to its other conclusion would be -- and I'm not suggesting that there's any transmission provider out there that does that, but the other side would be any integrated company could designate any network resource any time they wanted in any priority and kick anyone else out and I don't think that -- again, please, I'm not suggesting anyone's doing that and I believe no one's doing that. But that would be the other side. If you say that if you do that, you're somehow taking jurisdiction over service to retail load.

MR. HEGERIE: By putting it up there, it removes that perception issue that we were talking about earlier, that perception that that kind of discrimination could occur.

MR. NAUMANN: No, it's saying that the evaluation must be done by the same set of rules because again that comes down to -- one of the criticism we've heard is -- I'm not going to take up your time going through the history of CBM, which I'm sure no one really wants to hear, but if you're going to use CBM, are you going to expand your system when transmission is no longer adequate to serve native load because of the CBM margin? That's a big issue. People would be more likely to accept the use of CBM if everyone's subject to it and it drives the expansion of transmission system for native load as well as for third parties.

MR. HEGERIE: Thank you.

MR. HEDBERG: I had one quick question to ask about transparency. There's been some comments made about the provision of information versus data. One of the areas where we were looking for more information than just data was giving some narrative reasons for the changes in ATC. But we've heard a lot of responses about the relative burden of making the transmission provider post, in the narrative form, what has happened, why ATC has changed. I wonder if anyone has any comments on that. We've heard some folks say that you'd have to have fairly sophisticated customers to appreciate that just the data changes in the ATC, so we thought going towards providing more meaningful information on the changes in the ATC would be appropriate. Do you think we've struck the right balance in our proposal?

MR. MICHAEL SMITH: Yes, Dan, I think the Commission has between raw data and narrative. With respect to the raw data, I'll take my chances. Right. We live in the information age. Our ability to receive and process vast amounts of data is incredible now and so that would be helpful. I don't buy into this burden argument on providing the raw data. The same thing on the narrative. The narrative is pretty easy to cook up and it provides texture around that data and I haven't heard a credible argument as to a downside to providing that to the marketplace to facilitate commercial transactions.

COMMISSIONER KELLY: I would assume that when we give policy direction, assuming we give policy direction, that a lot of the policy direction is going to depend on input we get from the users of the system as to what they use it for, and I would assume that. Do we have that kind of input now or would we have to ask more questions?

MS. BARRON: Well, I would look forward to what Mr. Mucci said he's planning to submit. I didn't see that in the comments we have so far.

MR. MICHAEL SMITH: I'd just like to add we took off -- in the NOPR, the Commission put together a list of certain modeling data and said is this right kind of thing that transmission customers would be looking for? We took that list and expanded it to a fairly substantial list broken down into modeling data, modeling support information and then benchmarking the forecasting data would suggest that that might be a good starting point. I'm not aware of any comments in response from anybody that said that that's not the right starting point for a subset of data to start disseminating.

MR. NAUMANN: Commissioner, we're very supportive of narratives, but I do think there, at some point, does become a balancing act. For a long-term firm transmission service there's plenty of time to try to come up with narratives. For hourly, non-firm transmission service, I personally think it's a fairly useless task. Maybe the only narrative that can go out there is if a major transmission element went in or out of service or something like that that might have affected the numbers, but to ask somebody in the middle of calculating all of that each hour to try to figure out why with the load and the dispatch changes if there are no topology changes. You would assume the changes are then very complex. That might be a burden. So I think in the shorter operational timeframe, other than changes in topology or things like that, it does become a little bit not as helpful and more hurtful to try to put that out and analyze it.

CHAIRMAN KELLIHER: Any other questions?

MR. JERRY SMITH: I actually wants to say thanks, Steve, because APS agrees with you there and we feel that if you did do that real time type narratives it would be a very burdensome -- operation would be very costly and we don't know that the customer would get any benefits out of it. We're not sure they would be willing to look at all this stuff while they're doing it. So I think longer term, yes, but short-term stuff would be very burdensome on the operators.

MS. ERIC: Nobody proposed the three CBM options. The first point is that NERC improved the existing standard. The second one is that CBM be treated as a firm service and there should be a charge for that. And the third one would be elimination of CBM and designation of network resources that are outside the control area. Which option do you prefer and why?

MR. NAUMANN: I'm absolutely opposed to Option 3. I think that would harm reliability. There's reserve sharing going on and you would change to where -- I don't know if Mr. Kormos is still in the audience. Is Mike still in the audience? But I think he'd tell you, if you eliminated CBM, the IRM and PJM would no longer be 15 percent. It would be above 15 percent. I've actually seen a graph showing, depending on the CBM, how the IRM changes. We'd be opposed to Option 3.

Exelon would support Option 2 that there would be a charge or rather not a charge, an increase in the divisor would be treated like a long-term reservation because you can't charge retail load. They've already paid for that. But if you increase the divisor -- getting into ratemaking now, I'm afraid -- the megawatt divisor by the amount of CBM you would lower the point-to-point charge. That way for those using the CBM -- I don't want to say paying for it, but it would be accounted for such that for those who don't have benefit of the CBM they would be effectively paying a lower charge because less transmission is available.

We said that I think about seven years ago and one of three or four CBM proceedings that the Commission's had since the beginning.

MR. LOHRMAN: I think this speaks a little bit towards the issue of consistency because they way the CBM is calculated and the way the CBM is used can be different in different areas and going back and getting to be more consistently applied could be helpful.

CHAIRMAN KELLIHER: Mr. Smith, something quick?

MR. MICHAEL SMITH: Why don't we go ahead and wrap up? If that's where you're headed, I don't have anything substantial to add.

CHAIRMAN KELLIHER: I think that will have to be the last word for this panel. I want to thank all of you for helping us and we're going to take a shorter break than planned, but resume on time at 2:00. Thank you.

(Recess.)

CHAIRMAN KELLIHER: We're going to resume. Please take a seat. Let's close the doors.

Why don't we start with Mr. Don Furman, Senior Vice President, PPM Energy on behalf of the American Wind Energy Association.

In the back of the room, could you please step out into the hallway or stop your conversations. Thank you. We regulate some of you, I think.

(Laughter.)

CHAIRMAN KELLIHER: And I know who you work for.

(Laughter.)

CHAIRMAN KELLIHER: So with that, Mr. Furman, why don't you begin.

MR. FURMAN: Thank you, Mr. Chairman.

I'm here on behalf of AWEA today largely because I can't hold a job. I'm probably unique among the wind development community as being the only executive whose operated a transmission system in the past. I spent probably the last year of the last 10 years as an executive of Pacific Corp where I had jobs essentially responsible for regulation external affairs, but also several years operating their transmission system. I've also got a fair amount of experience prior to this experience as a developer and marketer and as a customer of a number of transmission providers, including many of those who are in the room and speaking today.

PPM Energy is the second largest, by some measures, wind developer in the U.S. We control about 1600 megawatts of capacity. We have as a goal getting to 3500 megawatts by 2010, wind and other renewable resources, but particularly wind are very, very important and I would emphasize very popular these days and they're popular for different reasons and it cuts across red versus blue. It's East Coast/West Coast, in the middle, rural, urban and it's because everybody gets something from renewable resources.

We limit greenhouse gases and help to improve the situation with regard to greenhouse gases. Fuel diversity, which is an important factor now that we've seen so much volatility in the gas market reduces our reliance on foreign resources and another thing that is important is the economic development, particularly the wind industry injects into rural America. If you go to some of these project dedications, the impact that it has on the family farm and the ability for people in rural America to keep their kids at home, give them jobs and maintain their communities is really important.

And the last thing I would add is this Administration has set as a goal having wind power become 20 percent of the nation's energy supply. So it's a very important priority for the country and it's a very important priority, I think, for most of the people in the business because wind is primarily located in rural areas and some distance away from the load centers, the biggest impediment to investment in wind generation is the lack of firm transmission capability and the Commission's efforts to promote construction of new transmission are important. They're critical but they are not going to come in time and it's going to be a real impediment to the development of the wind industry unless we can get more efficient use of the currently existing grid.

In the opening comments, Commissioner Kelly referred to -- that we all started out in this 888 business. It was about open access, but it's also about availability. That reminded me -- and please don't take offense to this Commissioner -- but it reminded me of my mother-in-law who likes to --

COMMISSIONER KELLY: I'm going to be a mother-in-law soon. That's all right.

(Laughter.)

MR. FURMAN: My mother-in-law never misses an opportunity to tell me what a great job she did raising my wife and she likes to tell me her philosophy is firm, fair and friendly and it just for some reasons those words popped into my mind because this is a bit of a reach, but firm is about adequate firm capability. I mean that's an important part certainly to the wind industry. Fair is all about open access. But the other thing that I want to leave you with is friendly is very important and wind is different from the rest of the resources. It is intermittent. It does create some operational issues that don't exist with other resources and so it's very important that transmission policies be made because we've got this national goal of increasing our percentage of renewable resources. We will never get there unless we think about the impact on renewables that transmission policy has. I want to really emphasize that.

This panel is talking about conditional, firm and redispatch -- and I'm wrapping up, don't worry -- about conditional, firm and redispatch and both of those are premised on the idea that we don't fully utilize the transmission system to its full capability. It all has to do with how we set ATC a couple of hours out of the year on a given path can reduce -- can mean that that path or that flow gate can't be sold on a firm basis and there's a lot of capability in the system that is not being utilized and whether it's the renewables business or other areas of the market, it only makes sense for us to take advantage of that.

So we are advocating very strongly in favor of that and we're advocating very strongly in favor of both products because we want the flexibility to use both products or either product where they're available. And with that, my time is up and so I will conclude. But thank you very much for the opportunity to be here. We really appreciate it.

CHAIRMAN KELLIHER: Thank you.

Before I recognize Ms. Alexander, I just want to say that I think some of the panelists have planes to catch and so it's important that we end at 4 o'clock. Does anyone plan to leave before 4 o'clock or can you all stay through 4:00? You can stay through 4:00. Great. So why don't we shoot to end at 4:00 because we go beyond that I know my wife will be very unhappy with me because I will be late to meet her. So let's stick to 4:00 and we'll go efficiently.

Let's now recognize Patricia Alexander, an energy consultant with Dixon Sharipo on behalf of the Electric Power Supply Association.

MS. ALEXANDER: Thank you. I am here speaking today on behalf of EPSA. The NOPA and the comments really posed three main questions. Whether the existing redispatch requirement should be maintained, whether a conditional firm product should be added to the OATT and what terms and conditions should apply to redispatch or conditional firm products? The answers to the first two questions are truly easy for me.

Redispatching conditional firm products provide an opportunity for customers to obtain transmission that would not otherwise be available or would not be available economically. Other than a reliability problem or congestion that potential exist in a few hours of the year, today the only way to get service is to construct costly upgrade. If the OATT is not amended to ensure these products are provided in circumstances where they can be offered without adversely affecting reliability, the OATT will impose unreasonable cost on customers. It will create unnecessary barriers to competition and will be at odds with the objectives the Commission's open access policies.

The third question I admit is a little bit more difficult. What are the terms and conditions of the service? But these problems are insurmountable. The Commission, the industry successfully wrestled with difficult problems the first time around in the OATT the first time around and Steve Naumann talked about the What and the How Groups. The industry figured out how to do all the curtailment priorities that Commission put in the tariff that seemed impossible at the time. More recently the Commission and the industry together figured out how to provide interconnection and transmission as a separate product, which at first would seem to be impossible. So these can be solved if you roll up your sleeves and figure out how to do it rather than whether to do it.

Touching on a few of the questions that we tabled for today's conference. EPSA believes there's no reason to insist that the conditional firm product be defined based on a set number of REV years or based on the occurrence of a defined contingency. The fact that neither method may work in a particular case is no reason to arbitrarily exclude one option over the other from consideration. Once the study results are available, the transmission provider should be able to determine what methods are feasible. The customer can look at that, look at the advantages, the disadvantages of either and make a decision.

Also, conditional firm should be assigned to firm priority at al times when the condition is not triggered. When the condition is triggered, firm customers should have the highest priority over non-firm. Conditional firm should not be offered only as a bridge product until the transmission upgrades, regardless of cost, are completed. While it may often be the case that expansion can be affected during the term of the transaction -- and in those cases the transmission provider should put the expansion in its plan.

It may also be the case that the expansion solution is not economic. If the cost of mitigating a contingency that's expected to arise in only a few hours a year is prohibitive, it's simply not prudent to undertake that expansion, whether the transmission is being used by native load or by the OATT customer.

EPSA doesn't agree that customers should be forced onto "and" pricing as the means for obtaining compliance with the Commission's longstanding requirement for redispatch. The only thing that's advanced by the commentors in favor of "and" pricing are the very same arguments that were advanced 15 years ago in pinlack and Northeast utilities and Public Service of Colorado, other cases. The Commission has already determined that "and" pricing is not just unreasonable. The Courts upheld that determination and the passage of time can't legitimate "and" pricing. Charging twice was wrong then. Charging twice is wrong now.

There should also be no difficulty in establishing mechanisms for calculating and verifying redispatch costs. Again, the Commission and the industry have some experience in dealing with rates that are based on out-of-pocket costs. For 20 year, market-based rates were really called coordination cost-based rates and the energy prices were based on incremental cost. Today imbalance charges are based on incremental cost, so there are ways to measure, quantify and I would hope verify the derivation of these kinds of charges. Similarly, competitive suppliers can design and implement rates under which they could voluntarily offer third party redispatch service just as they design and implement rates for other power services today.

EPSA looks forward to working with the Commission and with others to develop some practical solutions to some of these "How To" problems.

CHAIRMAN KELLIHER: Thank you very much, Ms. Alexander. I want to welcome you back to FERC.

MS. ALEXANDER: Thank you.

CHAIRMAN KELLIHER: Now I want to recognize John

Lucas, Transmission Service Director, Southern Company Services.

MR. LUCAS: Thank you very much, Mr Chairman. Southern Company very much appreciates the opportunity to speak here today and provide comments to the Commission.

I'll start with the redispatch product. One revision that is suggested by the Commission is to provide a preliminary estimate of the hours and the costs for redispatch at the time a system impact study is done. That's problematic for several reasons. First being, the process works like this the provider does a facilities study at the end of a system impact study and that's where the provider indicates what improvements are needed to solve the constraints, the time needed to construct those and the costs. Having redispatch as an optional study before the facilities study is done, just tears that process apart and makes it unworkable, mainly for the reason the facilities study may well, in fact, identify improvements that are able to be completed before the start date of the service and the cost of the upgrades may not trigger OATT pricing it at all. When you compare the cost and timing of improvements to redispatch, it's the only way to know if building facilities is going to solve the congestion or not.

Turning now to some of the complexities and difficulties that operators have and transmission providers have in offering redispatch service, at the start offering redispatch it could very well reduce planning reserve margins. The provider, if he reduces generation output to accommodate a long-term firm point-to-point transaction, that's going to reduce capacity that the provider has to serve native load. And in most cases providers are going to feel that redispatching resources and possibly reducing reserve margins to unacceptable levels is not going to allow them to continue to offer service that not impairing reliability of service to firm customers.

As a result, I think the bottom line is redispatch options of the providers resources at peak are rarely possible without impairing reliability, given today's slim reserve margins.

Just a few more operational points, before offering redispatch the provider has got to be okay that he can manage the real time operational risk without degrading or impairing reliability of service to others. I think that providers typically rely on redispatch to manage reliability in real time. So if we offer redispatch based on a planning study result, it's going to reduce that flexibility. When you do that, then you're going to subject traditional firm service to more curtailments due to the fact that the redispatch scenario won't be available in real time.

And then lastly on redispatch cost recovery point, this is not "and" pricing. The Commission must allow providers to recovery the full actual cost of using their generation and the cost of using their transmission system. This is not "and" pricing. This is two separate and distinct services and the pricing should not involve any artificial price caps.

With the little time I have left, I'll just make a couple of observations on conditional firm. One big caution. Allowing conditional firm as a pseudo firm product, we've just got to make sure that providers are able to meet existing and future NERC reliability standards. We can't short circuit those. The provider must be able to do that and I would encourage the Commission allow flexibility in setting the service conditions. Customers and providers across different regions may prefer a menu of conditions. Let customers and providers negotiate the conditions within some set of OATT guidelines. One of the things we think would be the most workable for customers, transmission planners, transmission operators would be to give a load level, a set of load ranges, a set of seasons wherein those could be the conditions that are handed to a customer to say during those periods your service may be conditional. It seems to be a lot easier to predict and so forth.

Then one last point, both redispatch and conditional firm should act only as a transition mechanism until upgrades are in place. Otherwise, if you don't do it that way, the goal of encouraging new transmission investment infrastructure is going to be compromised if you don't consider upgrades to address the constraints that are identified in trying to offer the service.

With that, I conclude and look forward to your questions.

CHAIRMAN KELLIHER: Thank you.

Now recognize Lauren Nichols-Kinas, Public Utilities Specialist, Bonneville Power Administration. Thank you.

MS. NICHOLS-KINAS: Thank you, Mr. Chairman. On behalf of Bonneville, I'd like to express our appreciation for the ability to have this conversation and these comments were developed in the context of the work we've done at looking at conditional firm in terms of BPA's specific constraints and needs, so I want to caveat what I'm going to say with that.

BPA believes that conditional firm service has merit for increasing long-term from ATC in the Pacific Northwest. Conditional firm services appears to be the only viable approach to creating additional long-term firm ATC in areas such as the Northwest, which rely primarily on bilateral market structures and which have significant hydroelectric generation. Hydroelectric power is not suitable for creating long-term firm ATC through redispatch because of the uncertainties that are inherent in hydroelectric generation, which is the predominant source of redispatch for our region. Hydro generators cannot reliably predict when or whether generation will be available to provide necessary redispatch and cannot assure any particular pattern of generation dispatch or redispatch over a long period of time. Unlike thermal generation, hydro projects have multiple uses and must be operated to provide for navigation, recreation and flood control as well as the product of power. All of these uses can affect the way that the operator must dispatch the system.

In addition, hydro operators cannot predict the constraints on power production because of the need to mitigate the impact of the hydro system on fish. At times BPA could be faced with the need to generate additional power or even to sacrifice power production to protect migrating fish. Hydro operating plants for fish mitigation may change annual and near-term operations sometimes must be changed weekly.

Finally, a hydro system is operated as an interconnected unit. Release of water at an upstream project on the Columbia River will result in generation of power downstream later in the day or the next day. Unlike thermal plants, hydro plants in such a system cannot be dispatched independently. Therefore, at least for the Pacific Northwest, BPA supports the Commission's proposal for conditional firm service under the following conditions: to minimize the need for information system changes, BPA believes that conditional firm hours should have the same curtailment priority as secondary service. In addition, the e-tag should reflect that priority at the time of submission so that the transmission provider does not have to design a process in which to convert that transaction to the conditional firm priority at the moment of curtailment when time is very short.

To implement conditional firm service, BPA would expect to develop a counting function to ensure that each time a conditional firm curtailment was made the number of hours curtailed would be subtracted from the total of the conditional firm hours for that month or that year. If the full contract limit for the conditional hours for the month or the year was ever reach, BPA would then notify the customer, after which the remaining hours in the month or year would be e-tagged with the same curtailment priority as firm service.

BPA believes that the monthly limitations would be the most consistent with our ATC methodology. The transmission provider must be allowed to identify an appropriately conservative number of conditional firm hours for every conditional firm month. For each reservation, a conservative cap is necessary to protect other firm customers from having their transmission service degraded by the sale of conditional firm service while providing the purchaser of the conditional firm service with certainty with regards to its additional curtailment risk. This certainty would allow the potential conditional firm customer to determine whether the conditional firm service offer would meet its business needs. The product could also be designed so that the lower curtailment priority would apply only when the constraint requiring the curtailment occurs on a path or flow gate specific basis.

BPA would study the potential conditional firm offers by examining our posted flow gate ATC and our curtailment histories on those flow gates. When offered conditional firm service, customers should have the option of requesting construction to convert conditional firm service to long-term firm or accepting the conditional firm product on a long-term basis. This choice would allow each customer to assess the economic benefits of firming up the conditional firm hours or portion of the service. If conditional firm service could be offered only as a bridge product, some customers might be forced to reject the offer as too expensive, even though they could have used the conditional firm service to meet their long-term business needs.

In summary, conditional firm service can provide PTP customers with access to long-term firm transmission that they previously could purchase only on a short-term basis. As a next step, the industry should examine mechanisms to provide network service customers with comparable long-term access to this ATC as well.

Further, BPA recommends that the Commission take no action to preclude transmission providers from making this additional ATC available to NT customers on a long-term basis if they can develop an effective method for doing so. Thank you.

CHAIRMAN KELLIHER: Thank you very much.

Now I'll recognize Anthony Taylor, Director of Transmission, Williams Power Company. Thank you.

MR. TAYLOR: Thanks to the Commission and the staff for addressing the issue of OATT reform. At Williams, I'm responsible for providing technical and transmission expertise in support of commercial transactions and contractual obligations. Prior to Williams, I spent 13 years at Energy working every aspect of the transmission business, including planning policy design, operations and managing the wholesale billing tariff administration, compliance and system coordination functions.

While we applaud the Commission for the proposed changes, we respectfully recommend the Commission adopt transparency and clarity as the central theme of the new OATT. For instance, in terms of CBM, the Commission should require firm generation supply contracts in order to reserve transmission capacity at CBM. This will effectively hold transmission owners to the same sourcing standard as transmission customers are currently held. In terms of additional data posting to increase the trust, validate fair and nondiscriminatory treatment and to enhance grid reliability, the Commission must require the posting of real time power flows and monitoring limiting elements, constrained area and system loads and import and export limits for constrained areas.

In terms of redispatch and conditional firm service, the Commission should allow the customer to decide which services best meets their individual needs on a case-by-case basis, allow non-affiliated generators to participate in the provision of redispatch to ensure competitive pricing. And in terms of conditional firm service, the transmission provider must be provided with sufficient detail in order to make a decision on whether or not the conditional service is adequate to meet the customer's need, i.e., restricted time periods, specific load conditions or limits and contingencies.

The transmission providers would say that the

Commission, in fact, should tighten the requirements for reservation, retention and funding of the development of transmission capacity. The transmission customers would disagree. Transmission customers would argue that the proposed OATT enhancements do not go far enough.

Because of the lack of transparent operational data, the transmission customer is unable to foresee or to verify the validity of a supposed system problem. This lack of transparent operations directly impacts decisionmaking and jeopardizes grid reliability. To enhance the security of the grid, the Commission must require more than the posting of transactional metrics. The Commission must allow access to transparent operational data such as access to real time power flows across limiting elements, system load, export and import limits just to name a few.

In terms of the panel topic, redispatching additional firm service, I offer the following four points. Transmission providers contend that they do not use redispatching and plan to serve native load or network load. I disagree. Transmission providers develop and plan to implement operating guides and procedures as a means to mitigate expected contingencies while continuing to meet load rather than investment in infrastructure. Transmission providers do this either by changing system topography or altering the dispatch of selected units; (2) transmission providers that if conditional firm service is offered, they must be allowed latitude to cancel the service as system conditions change because they do not have the tools to predict all of the circumstances that may arise. This is a smoke screen and the risk of unknown assumptions in offering additional firm service is no different that the risk transmission providers currently accept in the provision of firm or network service today; (3) transmission providers express concern over the free ride effect if party A chooses to take conditional firm service and party A opts to upgrade the grid, effectively lessening the probability of the identified condition occurring. This risk is no different than a customer choosing to make network upgrades to ensure deliverability with firm service. The grid is enhanced for the benefit of all transmission customers, including non-firm and native load; (4) transmission providers also contend that, if they are to offer conditional firm service, they need a simple threshold test like load level to avoid confusing the system operator with complex or varying terms and conditions. NERC certified system operators are used to dealing with multiple operating guides, standards and complex procedures to ensure the integrity of the grid in the balancing of load and generation in the provision of transmission service.

MR. HEDBERG: One minute left.

MR. TAYLOR: The transmission provider can provide his operators with a simple crib sheet categorizing segmented by customer, condition, limit, hour, et cetera. The provision of conditional firm service is fundamentally no different to the interruptible services historically offered industrial customers.

In conclusion, transparent, redispatch conditional firm service or transmission service products that will serve to increase more efficient use of the grid lead to infrastructure build out and enhanced system reliability for all market participants. The transmission customer must be allowed to choose which product best meets its needs on a case-by-case basis. Transparent real time operational data such as system load, power flows across limiting elements and transaction-specific conditions all serve to advance the competitive marketplace.

That concludes my remarks and again, thank you for the opportunity to address the Commission.

CHAIRMAN KELLIHER: Thank you.

Now I want to recognize Natalie McIntire, Senior Policy Associate, Renewable Northwest Project and I think you actually have the prime location for the whole day because you have the last word here among the panelists.

(Laughter.)

CHAIRMAN KELLIHER: And you're at least the second RPI graduate that we've had.

MS. McINTIRE: Where I come from on the West Coast, people don't know what RPI is.

CHAIRMAN KELLIHER: The winters were kind of touch. With that, why don't a recognize you and look forward to your comments.

MS. McINTIRE: Thank you. I think I'll try to leave the last word for you, though.

(Laughter.)

MS. McINTIRE: First of all, I want to thank you all for having me to participate on this panel. We appreciate the opportunity and I want to briefly state that RMP is a regional non-profit advocacy and policy organization in the Northwest working to increase the generation and sales of renewable energy. Our member organizations include energy companies, consumers organizations and environmental groups.

I also want to note that I was a panelist in a workshop FERC held in Portland in March of 2005 to discuss new products, including conditional firm and we've also filed comments following that workshop and on this current docket. So we've been very pleased with the Commission's interest in developing new products like conditional firm and redispatch as tools for utilities to make more efficient use of their existing transmission systems. These products can help bring on new generation resources to serve load and in some cases provide a bridge until new transmission lines are built.

I'm going to focus my comments on conditional firm, but I want to briefly make a few comments on the importance of both of these transmission products. Utilities and transmission providers are experiencing greater use of the transmission grid for more complicated market transactions than ever before and at the same time there's been limited investment in transmission additions over the past decade or so. So redispatch and conditional firm can make greater use of many of the transmission paths that are congested on a contractual basis, but where capacity has shown to be available in all but a small number of hours of the year.

We believe that the Commission should not be asking which one of these products is more appropriate for transmission providers, but should be requiring that transmission providers look at both of these options as ways to offer new transmission service. In some cases conditional firm may be less costly than redispatch and may provide a solution to a customer's needs where redispatch is not an option. And for many utilities conditional firm may be simpler to implement. But ultimately, for both of these products to enable the financing of new generation resources, it's essential that customers be able to predict with as much certainty and transparency as possible the cost of obtaining these products before they sign contracts.

So in months were no firm capacity is available, two options have been recently discussed for the conditional firm product. Customers could take conditional firm service subject to a defined contingency, contingency option, or subject to a lower than firm curtailment priority for a defined number of hours in defined period, the curtailed hours option.

We believe that both of these options can be implement, however, the curtailment hours option provides the greater certainty that will be more likely to result in transmission contracts that can enable new generation resources to come online and get financing. Conditional firm service has been discussed through a public process at Bonneville Power Administration and many of the implementation details have been considered and addressed there and RMP believes that this is a viable product.

I want to just briefly describe some of the key elements of conditional firm product that we think are necessary in order for it to work for financing new generation. It must be a long-term product offered to customers in the long-term firm que. In months were the transfer capacity is shown to be available, customers should be given firm service and treated like all other firm customers. During the months where no firm ATC is available, the conditional firm customer should be curtailed with secondary network customers for up to the defined number of conditional hours or under the specified contingency and that contingency or defined number of hours needs to be set at the beginning of the contract and must not change throughout the contract. This less than firm curtailment priority should be invoked only to maintain reliability and should not be called on for economic reasons.

If conditional firm is being used as a bridge product until new lines are constructed, customers need to be informed of any requirement or financial contribution to the upgrade at the beginning of their contract and we also think that conditional firm must allow utilities to designate a resource as a network resource.

Having worked with Bonneville over a significant time to identify a critical implementation details for conditional firm product, we recognize that there is more than one way to implement this product and therefore we suggest to the Commission that you task a group of stakeholders with working through the details of these products that would allow the Commission then to include a workable set of criteria for new products in your OATT revision.

Thanks again for letting me participate and look forward to questions.

CHAIRMAN KELLIHER: Thank you very much.

Alex, anyone want to start? John?

COMMISSIONER WELLINGHOFF: I'd be happy to. Thank you, Mr. Chairman. Thank you all panelists. I really appreciate your remarks and you've provided us with some good information this afternoon.

I'd first like to explore some generic areas and then I'll get into some specific questions related to your testimony. The first one would be do any of the panelists see that instituting conditional firm is way to efficiently use the grid is at all unfeasible? Does anybody see it as unfeasible?

(No response.)

COMMISSIONER WELLINGHOFF: I get no answers. I assume that everybody agrees that it is feasible. Let me ask that same question then with respect to redispatch and I'll exclude Bonneville because I understand your answers with respect to redispatch and your particular system. Does anybody see redispatch as unfeasible?

Mr. Furman?

MR. FURMAN: I think that redispatch has some challenges that conditional firm does not. How do you access the cost? That's something that needs to be worked through and I know, for example, when I was in the transmission business, we struggled with how to implement it under the current Order 888, so this is a good discussion to be had because I think the reason you haven't seen redispatch emerge is because it's not clear how to implement it or how the Commission necessarily wanted it implemented.

It is feasible but it is something that I think we have to nail down exactly what the rules are going to be. And I would also add, if it is after the fact pricing, that's not going to have much of a benefit. It will have some benefit to the operational efficiency of the system. It's not going to do anything to get new generation built, wind or other. For that you need more certainty and more ability to plan.

COMMISSIONER WELLINGHOFF: Thank you, Mr. Furman.

Mr. Lucas, I think you're reaching for your microphone.

MR. LUCAS: I did, Commissioner. I wanted to say it's hard to refute. You can't really that the requirement to consider redispatch option in offering service today is already in the tariff. So there's no real change there. The provider, though, is afforded two protections in evaluating that service, whether it would impair or degrade reliability of service to other firm users or degrade other firm uses of the system. I think you've got to keep those protections for the provider because, as I pointed out, if you're only looking at the providers resources, the provider is likely not going to have a surplus amount of capacity at peak that he can turn off and redispatch his system in a different way. You would put the provider at the mercy of having to go to the market and replace that capacity himself. So I think in my comments I made on the panel I was trying to illustrate to the Commission that's some of the shortcomings of why I think you don't see more redispatch being offered today is providers just don't think that they can accept the risks of not impairing reliability of service to others.

COMMISSIONER WELLINGHOFF: Actually, let me follow up on that because that was another specific question I had for you with respect to your testimony. Would you see it possible then to provide redispatch conditionally upon the reliability constraints? In other words, you could probably spell those out at what points you'd have to invoke those and so forth.

MR. LUCAS: Excellent question and in fact, it's done today. In the planning models the way the system is planned, you stack all your firm commitments and all the load of the network native load customers. There's a cushion there then built into the system that allows the provider in real time to manage reliability with just a slim cushion of resources that he might redispatch. And in fact, today a number of providers are dispatching in real time to avoid curtailments. So it's taking place. The reliability tool that's in the toolbox is being used.

If you force, in the planning process, a requirement to say carve out a requirement to offer redispatch, you're going to take that reliability tool away.

COMMISSIONER WELLINGHOFF: So your companies actually are using redispatch in your operations today?

MR. LUCAS: Yes, Commissioner. Every day.

COMMISSIONER WELLINGHOFF: Are you relying on that redispatch and planning for native load?

MR. LUCAS: No. There's a difference. We do not integrate new network resources on the assumption that we can redispatch around a problem. The reason we don't do that we have to attest to our states that that capacity is certifiable, just and reasonable. It will be there to serve the load at all hours. We cannot assume that there is some redispatch combination we can use to work around to run that resource.

Now that's not to say we don't have operating guides, operating procedures. We can take lines out of service. We can switch, configure lines. We do that with respect to conformability. We do it for our resources. We do it for transmission customer resource. We don't discriminate.

Mr. LUCAS: -- not to integrate a firm network resource that we've certified to a state commission. We do not.

COMMISSIONER WELLINGHOFF: Okay. Let me ask a question with respect to some commenters have -- no, let me ask another one first. Assuming that you consider both conditional firm and redispatch to be feasible products to offer, excluding Bonneville and the Redispatch, did any panel members see those as mutually exclusive, or are they things that both products could be offered on a system? Mr. Lucas?

MR. LUCAS: I'll answer it, yes. As I said, I think the commitment to offer the redispatch as a solution for a transmission constraints already exists. It's hard for me to define that as a product. I think it's an existing requirement and it needs refinement.

The conditional firm, I think, is a viable product if you can work out the conditions between customers and providers. As a provider, if we can be comfortable that the conditions that are there that we can hand to the operator in real time and have him manage not just one or two transactions; he may be having to manage 10 or 20 transactions.

If we can give him the tools, if we can give him the conditions, there can be predictability and certainty and about it, we would want to offer the service and get the revenue. I mean we would not -- our threshold would be make sure we don't impair reliability in creating the product.

COMMISSIONER WELLINGHOFF: I saw you, I think, sort of nodding your head when Ms. McIntire was talking about a stakeholder process to determine these criteria. Would you agree with the criteria that Ms. McIntire made?

MR. LUCAS: I applaud the suggestion. I think the Commission has done that in similar outreach workshops, and I think there should be follow-up, and there should be -- there should be -- don't be too prescriptive about the conditions in certain areas of the country.

There may be a need for flexibility in how you define those conditions. Tying it to hours, we struggled a bit with that. An ability of a planner to project how many hours of conditional firm might be there five years in the future, it's just like me trying to throw a dart at a wall with my eyes closed.

I mean I don't know that that's going to be valuable information. If I can give load levels, if I can give months of the year, customers will then know we can provide information that would show the load is growing.You can look at load profiles in prior periods. You'll have a much better feel for do I need to go to the market and get a hedge resource, etcetera, to back up that. The provider will be giving you more warning I may have to call on the conditions that go with this service.

COMMISSIONER WELLINGHOFF: And let me get to this issue about information or perhaps conditional firm in part, but maybe more importantly for the potential for redispatch.

I know some commenters have suggested that real time dispatch be made transparent. Is there anybody here who would object to making real time dispatch transparent? Mr. Lucas?

(Laughter.)

MR. LUCAS: Once more, you said "real time dispatch"?

COMMISSIONER WELLINGHOFF: Yes.

MR. LUCAS: You didn't say "redispatch."

COMMISSIONER WELLINGHOFF: I'm sorry. I meant redispatch.

MR. LUCAS: Okay.

COMMISSIONER WELLINGHOFF: Excuse.

MR. LUCAS: That might be a little more tolerable.

COMMISSIONER WELLINGHOFF: I misspoke, yes. Real time redispatch.

MR. LUCAS: Redispatch?

COMMISSIONER WELLINGHOFF: That's correct, yes, and let me read from one of the commenter's definition here, so we're all on the same page.

"Requires the transmission provider publish a dynamic real time value of what would change -- what it would charge to provide redispatch service at specified congestion locations within the transmission provider system, and at specified flow gates at the borders of the transmission provider's system."

That's, as I understand it, what people are meaning by transparency in a real time dispatch, redispatch.

MR. LUCAS: Yes. I think that needs a lot more discussion and debate. To start with, if you require that for the transmission provider's resources, again, you're reducing some of his ability to serve native load when you do that.

If you extend it to the market, if you say "Well, you can encompass other resources in the market, you can reach out to non-affiliated resources, you get back to a point made on the planning panel this morning with respect to operational control."

COMMISSIONER WELLINGHOFF: Let me stop you for a second. We're not asking anybody to actually put that out on the market. I'm just asking you simply publish the dynamic real time value. You'd publish it.

I'm not saying you'd necessarily have to do anything with it, you'd have to accept any values coming in.

I'm just saying make that transparent. That's all. Is there any problem with that?

MR. LUCAS: And this would be a value for the cost of redispatching on a particular flow gate?

COMMISSIONER WELLINGHOFF: Yes. Then we'd have the information.

MR. LUCAS: Well, one of the difficulties --

COMMISSIONER WELLINGHOFF: I'm not talking about instituting locational market pricing everywhere, I'm not talking about anything like that. I'm just simply saying, to get that data out there.

MR. LUCAS: I'm back with you. But from the transmission provider's function, and I speak from the transmission function for Southern Companies, we don't have pricing data that we would have to use to determine the price on each side of the flow gate in the transmission function. We don't have that.

I would think it would be a serious conflict with the existing standards of conduct for us to have to go into our merchant function or into our generation group and get costs associated with deltas of generation on each side of a flow gate, and then make those publicly available.

I'm sure our generation arm would have some concerns about the cost of generating being made public, etcetera and so forth.

COMMISSIONER WELLINGHOFF: Thank you. I don't think I have anything further. Thank you, Mr. Chairman.

COMMISSIONER KELLY: Don, did you have comments?

MR. FURMAN: Yes. I wanted to make sure that it was clear. Utilities today do not just redispatch for reliability purposes. They do it for commercial purposes, and well they should.

Any economic player in the market who sees an opportunity to incur a cost over here in order to make a profit over here should do that. That's the way markets work.

So it's not just done for reliability purposes. It's also far from clear that any time you would redispatch, you would see a reduction in reliability, whether it be planning margins or otherwise.

The whole premise around the original Order 888 provision was that this would all be done within the parameters of Reliability Council rules and any other rules.

So I don't -- I guess I disagree with the -- if that's the premise that's being stated, I disagree with the premise that there's necessarily degradation in reliability, or that it's only being done for reliability purposes.

That really, the fact that it is being done for economic reasons, I think, is at the crux of the problem, that it's being offered to native load. It's not being offered to other players in the market.

COMMISSIONER KELLY: Lauren, is Bonneville concerned about reliability in proposing to offer or agreeing that a conditional firm service would be something you could offer?

MS. NICHOLAS-KINAS: We wouldn't expect to implement a conditional firm service --

VOICE: Your microphone.

MS. NICHOLAS-KINAS: Oh. We wouldn't expect to implement a conditional firm service until we had the information systems in place to ensure that we could keep the reliability at the level that we think is critical.

COMMISSIONER KELLY: And how do you determine that?

MS. NICHOLAS-KINAS: Well, while we do share the concern regarding the potential for decreasing the consistency with which other firm customers would receive service. So what I expect that we would do is --

COMMISSIONER KELLY: And explain to me how that would happen?

MS. NICHOLAS-KINAS: Okay. Which of those would you like me to answer first?

COMMISSIONER KELLY: Explain to me how the consistency of their receiving firm service would be decreased by someone else getting conditional firm?

MS. NICHOLAS-KINAS: Okay. So again, I'm speaking within the framework of how we are thinking about the product, which is largely in terms of we would define some specific number of hours in the months in which we did not have long term ATC available over the flow gates that were necessary for that request.

So if we erred and defined that too generously, what would happen potentially is that we would have more curtailments, where in reality the conditional firm service customers should be cut, in the same manner as the network service customers. But we would run out of those hours and therefore have to cut them as firm customers.

Because it's basic math, it's a zero sum game, we would then end up doing either more curtailments or more curtailments and more megawatts on those existing firm customers as a result potentially. So that's the concern we're trying to mitigate there.

COMMISSIONER KELLY: And okay. So I understand that. So you're saying that at any point in time, there's a potential of curtailment of firm customers? If you have a conditional firm customer also taking at that time, it might increase the likelihood?

MS. NICHOLAS-KINAS: Yes.

COMMISSIONER KELLY: So if the conditional firm customer is not going to be cut first, if there's a curtailment during the time that I don't actually long term firm ATC to offer them, so if they are not curtailed first, then they're going to be curtailed in the same bucket with the rest of the long term firm customers.

The inherent implication there is there's more megawatts flowing over that flow gate and therefore I have to make a larger cut, and there would be additional instances most likely where I would have to do a firm cut, where just non-firm or secondary NT cuts might have otherwise sufficed if those hours were correct?

MS. NICHOLAS-KINAS: Uh-huh.

COMMISSIONER KELLY: Can we use numbers? Let's say that you can send 200 megawatts across a line.

MS. NICHOLAS-KINAS: Okay.

COMMISSIONER KELLY: And let's say that you have it contracted for 200 megawatts, but it's only used one hour a day, the 200 megawatts.

MS. NICHOLAS-KINAS: Okay.

COMMISSIONER KELLY: And that's non-peak. The rest of the time of the day, it's only used 120 megawatts. So are you saying that if you had 80 megawatts available conditional firm during that day except for that hour, and you gave that 80 megawatts out in conditional firm, why does that change the reliability of the line?

MS. NICHOLAS-KINAS: So that's not changing the reliability of the line. That's changing the impact on the other existing firm customers.

So their experience with curtailments is likely to increase if I define that 80 incorrectly, or if I -- if the one hour is actually two hours, for example.

COMMISSIONER KELLY: Okay. But it wouldn't decrease otherwise? I mean it wouldn't decrease except if you define the off peak. Okay. So when you decide whether to make conditional firm available for off-peak, what process would you go through?

MS. NICHOLAS-KINAS: So we calculate our ATCs for each of our flow gates on a monthly basis. So we have one member for all of the hours in each month. We would, when a request comes in for this POR to that POD, we determine how many megawatts are necessary on each of those impacted flow gates.

If we found that on one of those flow gates that was necessary to grant that request, we only had ten months of long-term firm ATC available, we would then, you know, on our system we would look at probably trying to define those two months as conditional firm.

We would then, and I'm hypothesizing here a little bit, because we've never tried to do this, but then I expect that we would go and we would look at historical curtailment experiences in those two months specifically, to try to determine what we think is a reasonably conservative number of hours that we would need that would keep our existing customers reasonably in the same position that they're in today, and still allow us to provide the potential customer with some economic certainty of what that transaction would mean to them if they accept it.

COMMISSIONER KELLY: Okay, and if you come up with a number greater than zero, then would you make it available as conditional firm?

MS. NICHOLAS-KINAS: Under what conditions?

COMMISSIONER KELLY: If there is -- if you think that it could be done, then would you make it available?

MS. NICHOLAS-KINAS: Assuming that the proper systems were in place to allow us to administer it in a way where we actually could manage it properly, yes.

COMMISSIONER KELLY: Okay. So you would pretty much be able to know in advance whether you'd have that product available to sell or not, if you modeled your system correctly and were conservative about reliability standards?

MS. NICHOLAS-KINAS: So because of the way that our system is very networked and we have multiple flow gates and each request essentially impacts multiple flow gates, we would need to examine each specific request to see whether they were in the position, first of all, of needing that and then whether or not we could offer conditional firm, and the terms that would then be associated with that.

I do want to highlight the need to maintain some flexibility in the terms that we would apply to that, and then allow the customer to decide whether those conditions would provide them with an economically viable transaction or not.

COMMISSIONER KELLY: Does anybody provide conditional firm yet now?

MR. LUCAS: Commissioner, we've done one experiment with it, and it was based on a particular transaction in a load and generation pocket in our system. It was a four-month experiment across the summer.

It would say it was somewhat successful. The customer knew the conditions; we put additional visuals for them on OASIS so they could know the balance of load and generation where they might be curtailed.

Again, I think it's just a caution. As Lauren said, if we determine the conditions in a planning laboratory, and then we hand that off to the operator, I think it's just a -- it's a tricky balance, then. Okay, the operator, certainly he could do it for one or two transactions. I don't think that's anybody's running scared from that.

But if there are ten or twenty transactions with different hours, maybe linked to different constraints around the system, I think it would be nearly impossible for the operator to manage. I don't know what tools he would use to do that.

MS. ALEXANDER: Another example of where a version of conditional firm has been provided for is a special protection system for a generator. Often, a generator will not be able to get firm service out from its facility to the full amount of its capacity.

But if it could be monitored so that the generator can be turned off within a certain number of minutes after the contingency arises, then firm service could be provided at a greater amount, and there are definitely generators in this country that operate with SPSs, and get the benefit of this increased transmission capacity. The systems are set up to curtail it within the reliability criteria time frame, so that all the NERC standards are met. In a sense, it's a form of conditional firm service.

COMMISSIONER KELLY: Does NERC allow this?

MS. ALEXANDER: Oh yes, yes.

COMMISSIONER KELLY: Okay.

MS. ALEXANDER: They have standards built around SPS systems, special protection systems, specific standards built around them.

COMMISSIONER KELLY: Can those same standards be adopted to conditional firm?

MS. ALEXANDER: I think in some instances, conditional firm would be similar in a sense that it's contingency-defined. The one I'm describing is that you have a limiting element that you can monitor, and then have a triggering that goes back -- I'm not the engineer talking here, but it goes back to turn off the plant when it needs to be turned off.

So I think in one instances, conditional firm, to the extent that this condition is this kind of a limiting element, could be set up in the same way.

MR. TAYLOR: We were -- Williams Power was offered a conditional firm product, and it was because our facility was located in a load pocket.

One of the concerns that we had that determined -- that led to our decision not to take the conditional firm service was that we were concerned about the transparency of the data, you know, what information would be available to us as the customer, so that we could foresee whether or not there was a system problem actually developing.

So to the extent that there is adequate transparent operational data available, then I think that we as a customer would be more likely or more inclined to take those type products.

COMMISSIONER KELLY: Because then you understand what the risk is that you're taking on?

MR. TAYLOR: Well, you can actually see. If it's -- let's say that it's contingency-based. Then you can actually see if you have load flow data, or if you have power flow data for that particular monitored element, then you can see in real time as that element starts to load up, you'll know that your condition is about to occur. It's also a means for you to validate the existence of a problem.

COMMISSIONER KELLY: But you couldn't get that data?

MR. TAYLOR: We had inquired about that type of information prior, and our internally our people were uncomfortable, because we had been unsuccessful in getting that type of transparency previously.

COMMISSIONER KELLY: Would having that type of transparency be important if conditional firm service were available?

MR. TAYLOR: I think that with any type of conditional firm service, whether you're limited based upon the number of hours or if you're limited based upon the terms of a particular contingency, whatever the condition is, the more information that's made available to the customer at the time that he's issued the service or offered the service, the more comfortable the customer will be in terms of whether or not he can assess the risk of assuming that service.

MR. FURMAN: Commissioner Kelly had something. I think this gets to one of the reasons why Ms. McIntire's suggestion about having guidelines and some flexibilities is probably important, because I think there are going to be instances where, for example, both the customer and the transmission provider may be able and want to specify, for example, a certain number of hours out a specific month or season when the firm's not available.

Certainly there are instances like that on the grid where you can see that, you know that, and it's more certain, and then both parties can sort of cut off the tails of their risk and say we know what this is going to be inside.

I think there are going to be other instances where it's more akin to what Pat was describing from a reliability standpoint, where you need to have a contingency-based thing.

But I think that we'll be more successful with this if we can have some degree of flexibility to address different sort of situations.

COMMISSIONER MOELLER: I'd like to talk to my colleagues from the Northwest. I think in terms of giving this maybe a little bit of recent historical perspective, Natalie, Don and also Lauren, can you talk a little bit about how this evolved, the request to Bonneville about the conditional firm and what kind of came out of that? I think that might be instructive.

MS. McINTIRE: Well, the concept of conditional firm, I'd have to say, did not originate with R&P or necessarily with Bonneville, I don't believe, but with AWEA, at least from our perspective, working with AWEA as colleagues. You know, they encouraged us to be talking with our transmission providers in the Northwest.

So we were talking with Bonneville about that possibility, because their system is very constrained on a contractual basis. They have a very long queue, hard to get transmission service there. So we encouraged them to look at this possibility.

It took a while before that became an open dialogue, but then Bonneville began, what they call I believe, a new product process, something like that.

So R&P, working with Bonneville, got to be sort of the first effort going through that to discuss through this sort of open process a new product and gather stakeholder input and modify that proposal and we had a very good working relationship with them, I think. Like I said in my comments, we think the product is very viable, and the holdup that I understand there, and maybe Lauren can speak to it a little bit more, is this lack of computer systems in order to implement this type of product, where you need to be able to curtail certain contracts on the network before you can curtail others.

That's not a possibility right now. But should it evolve and those systems be developed, they seem interested in pursuing it.

MR. FURMAN: Just before I launch, I have to say Bonneville, what we do a lot of business with Bonneville on the transmission side, and they are a very good counterparty to do business with. They work hard at fulfilling their transmission obligations.

You know, we don't have a specific conditional firm discussion going on right now that I'm aware of. That could be completely wrong, but it happens. But I think that there is -- what is definitely true about the Northwest is that you don't have --

You know, because systems always have -- I mean let's think about this. Ten, fifteen years ago before 888, everybody ran their generation of transmission together. Everybody sat in the same room. Everybody was able to jigger this up and jigger that down and make this get over here and move that over there.

To some extent, 888 both required them to do for everybody else, but also made it a little bit harder to do that because of the code of conduct. The RTO West/Gridwest experience was that in fact, Bonneville has sold more transmission then, if you just look at it as a static system, they could deliver.

So actually Bonneville does redispatch in their system in order to meet their existing transmission obligations. You could call that planning for -- using redispatch for planning purposes, although I don't think that was an overt decision.

Certainly Bonneville has a lot of things coming at it. Between Judge Redman's fish decisions and you know, it is a complicated system and so on and so forth. But I think that over time, as we work on these things, there's a great capability for that agency to implement some of these tools.

I think both just because of the attitude of the institution but also, I think, they've got -- they have the ability to do it.

COMMISSIONER MOELLER: Lauren, again to follow up, I think Bonneville learned a lot, from what I've heard, out of that process as well. I'd be curious on your reactions to that and how it might apply to efforts in other regions.

MS. NICHOLAS-KINAS: First, I want to respectfully disagree with Don. When we're doing an ATC analysis for a specific request, we in no way examine whether redispatch can be used to grant that request.

In terms of our internal process, in looking at whether we could develop a new product that got the name conditional firm, we first started by really looking at our inventory and how we might be able to define a different kind of inventory with different characteristics, to squeeze more out of the existing transmission system.

So we did that by examining data for each of our flow gates, and looking at an essentially below duration approach. We found that on our system, the flow gates tend to take a shape where just a very few hours of the year, there's a steep drop, or a very high level of flow and then there's a steep drop, and then it becomes relatively flat for most of the hours of the year. Then there's a steep drop for a few more hours.

So in looking at what inventory we had, we're looking at that space between the ATC and the bottom of the steep drop essentially, as something that would be viable to try to sell in some different manner.

So the real challenge then becomes, I think, for us as an industry to define it in a manner that has characteristics that we can essentially have some meaningful level of consistency, but that we don't take the flexibility out for our system or someone's system who looks vastly different than ours. I think that is one of our fundamental challenges.

The second issue that I want to just point out is that in talking about conditional firm, I think we're all kind of describing different pieces of an elephant perhaps.

We don't have at this point a clear picture of what that might be on a nationwide level. So I do agree with Natalie, that it would be useful to put some more time in, in working to develop that as a larger group.

COMMISSIONER SPITZER: Thank you. This is John. I'm interested from a global perspective in integrating wind energy, and we do have this dilemma. Mr. Lucas spoke about speculation, five or ten or even 20 years out, and the complexity in attempting to make projections to comport with the conditional firm.

With regard to perspective projects, the developers need financing and those who provide financing are looking for some degree of certitude. So we have the chicken and egg formulation.

I've read the materials and we have a conflict of opinion, and I'm not sure how we resolve that. I'd like you to comment on that general issue.

Then, on a more specific point, to modify a bit Commissioner Kelly's hypothetical, in her hypothetical, she used the term "a conservative projection" for what would be available. It seems to me under the status quo, and I'm appreciative of Bonneville's efforts to move forward and accommodate the intermittent users.

But there don't seem to be any incentives to avoid overly-conservative projections, that would understate what would be available for a prospective developer looking to finance a project.

So what can be done? There don't seem to be any incentives on the other side. I respect the need for reliability, but it seems like we have a system that's kind of out of balance. We seem to have a -- the incentives would appear to be tilted against the wind developers.

MS. McINTIRE: I just want to point out briefly that we have never really thought of this product as specifically for wind or for renewable resources, but for all generators, or all transmission customers, for that matter.

We do think it is a viable product for wind. But I think you pointed out a really good point, that there needs to be transparency here also.

In the workshop that we had in 2005, there was a lot of concern on the part of some customers and some transmission providers that within those conditional months, where there was no firm ATC available, then all hours needed to be considered potentially curtailable at this less than firm priority.

I think that there is a reasonable place between all hours and an exact number. I think it is unrealistic for a transmission provider to be able to say "next year I know that exactly this is the number of hours" or in five years or in ten years.

But I think that there is a reasonable way to get to some number that is conservative, and protects firm customers, but also gives certainty to new generators.

Just sort of as a high level conceptual way to think about this, most transmission providers would tell you we're not going to need to do this in the low load hours, so we can cut those hours out of the month.

We've got then our high load hours, and there's no -- we're not going to have an adequate system, we're not going to have a reasonable system if we feel like we need to curtail secondary network customers, all of the high load hours in these two months. That would not be an adequate system to meet all the transmission needs for the market.

So what number in there can we come up with, that's between, you know, five or ten hours and all the high load hours, that's reasonable.

But I think that it needs to be a transparent process to come up with that conservative number, so that the transmission provider should say this is why we think we need, you know, this amount of buffer, and this is the historic numbers that we have to work with.

COMMISSIONER SPITZER: So there's some objectivity attendant to that conservative determination?

MS. McINTIRE: Right, yes. We're not going to get an exact number. I think that that would be unrealistic.

COMMISSIONER KELLY: Is this a NAESB kind of issue, or is this a system by system issue?

MS. McINTIRE: I am not familiar with all the work of NAESB, so I'm not the one to answer that question. Maybe someone else can.

MR. LUCAS: I can, Commissioner. I've been on the NAESB Executive Committee and now sit on the NAESB Board. I don't see that as an issue to hand off to NAESB. NAESB is business practice standard-setting.

It would need to be clearly defined in terms of what is the business practice that would be needed to address Mr. Spitzer's question of the right incentives to prevent conservative estimates on conditions. I don't see as a NAESB challenge.

MR. FURMAN: I'm a lawyer by training, and have just enough electrical engineering to be dangerous. I think the conservatism that you see -- you do see a lot of conservatism in the design and the operation of the system, and that's a good thing.

That's one of the reasons we have such a reliable grid in this country as opposed to other places. I'm sure you've been places where the lights go out.

However, it's also true that there is an incentive built into the system for conservative behavior, and you know, I understand this, because I've been on that side. Utilities don't get compensated to take risks, you know. It's a rate of return kind of business, regulated rate of return business. So utilities do have an incentive to hold on to flexibility and just general, I guess, excess capability in the system, because that reduces their risk.

Certainly you saw that in the Western energy crisis, when you know, utilities did let reserve margins get too low and when transmission didn't get built. You had, among other reasons for all of that, I think, was the lack of adequate capability. So we want to make sure that we don't go too far in doing that.

But conditional firm and redispatch both recognize that, and they seek to -- conditional firm seeks to carve out that piece that really isn't needed for that redundancy and that reliability.

Similarly, redispatch seeks to find places in which the economics of the situation dictate that it's silly to hold all that stuff there. We can go buy it some place else and rejigger things and create more value for society.

So I guess I appreciate Commissioner Spitzer's comments. I think they're right on. We just need to have a full view of all the factors that go into that conservatism.

COMMISSIONER KELLY: How would we make the decision about whether or not it would be important or worthwhile to require utilities to considering offering conditional firm?

MR. FURMAN: Well, I mean, first of all, the reliability criteria are already there. They're established. As long as we stay within those, I don't think there's anything at all to say that you shouldn't require -- and again, I agree that there needs to be some flexibility.

You would want to do it with guidelines. But require subjective guidelines and with some flexibility and room for negotiations for utilities to do that. I think that's what we're here. I think that's definitely how we feel.

COMMISSIONER KELLY: I guess the downside is the cost involved in having the utility look into that.

MR. FURMAN: But I don't think the cost is extraordinary. I mean, what you're using -- look. First of all, you're looking at system studies that are predominantly already being done. You're looking at the kinds of operations that are predominantly already being done.

And so it's incremental cost and in the grand scheme of things, I don't think that cost is considerable. As long as we're not talking about the specific redispatch cost. I mean those redispatch costs may be considerable, and in that case you won't do it.

You're looking for those instances where for relatively little cost you can rejigger operations to create some capability.

COMMISSIONER KELLY: Thanks.

MR. LUCAS: Commissioner, I'm sorry. My mind just went blank on the point you had raised. I had it there. I lost it for just a minute when Don started talking.

One thing I did want to go back to Commissioner Spitzer's comment, and maybe it will float out to the front of my mind. Incentives to prevent conservative projections. To me, the biggest one that's in the tariff today is, the way the Commission's proposed it, the provider gets to collect the full rate for the transmission service.

So I don't think I'm going to keep customers very happy long if I'm taking the full transmission rate and not sticking to -- pretty closely to the projection on the conditions that were given. I think that's the strongest incentive.

Another strong disincentive is that I don't think conditional firm should be considered at all unless it's a bridge mechanism to get transmission built to relieve the constraint. I just don't think we ought to create a market that's centered around just conditional firm, because you won't get new infrastructure.

If a provider gets a request, and conditional firm's not there, and he doesn't have the capacity in the system, he wants to build that capacity out subject to the appropriate pricing and cost recovery. So I think that's the incentives.

COMMISSIONER SPITZER: Mr. Lucas, I absolutely agree with respect to existing generation, both comments; one on remuneration for the service. You get paid the fair dollar or what Mr. Wellinghoff said a few hours earlier, and with respect to the relieving a constraint.

But with regard to prospective introduction of intermittent resources, you don't have the compensation issue. You're looking -- the generator, the developer is, with gimlet eyes, looking over projections. If the numbers don't pencil out, the project doesn't get built, based on variables outside the control of people proposing to build. So there's a degree of frustration.

Then secondly, you don't want to overbuild. I mean Lord knows we need enough transmission. We have to be in the right place. Where there is an underutilization of the existing grid, it would be bad policy to require duplicative transmission to meet 20 hours, you know, or five hours or whatever in, you know, a 365-day year.

So we might -- a consequence of your position might be to overbuild where it's not necessary.

MR. TAYLOR: Yes, Commissioner. In terms of your question concerning what would it take or to offer or to institute conditional firm service from a study perspective, as Don said, right now the study's already being done.

When a customer requests transmission service, then if the ATC is unavailable, then the provider's going to -- if the customer requests, then the transmission provider will conduct a system impact study, and as a part of the results of that impact study, the provider will identify what the limiting elements are or what the limiting constraints are.

So in terms of providing a conditional firm service, it's just a matter of that provider saying that under these sets of restrictions or projected restrictions, I can provide you the requested capacity, unless these events occur.

Then it's a matter of is that service provided in terms of the occurrence of that contingency, the hitting of some threshold load level, or some restricted number of hours of operation.

So from that standpoint, the data has already been compiled. Would you agree gentlemen?

Secondly, in terms of whether or not the service should be provided as a bridge service or whether it should be provided to any and all customers, from a transmission customer perspective, it may not always be economically feasible for the customer to pay for the upgrade or the time may not be sufficient for the upgrade to be implemented.

COMMISSIONER KELLY: So as a customer, you might be very happy with the service?

MR. TAYLOR: Yes.

COMMISSIONER KELLY: And what use would Williams Power put that kind of transmission product to?

MR. TAYLOR: If we have a, say a long term -- if we have a customer that we'd had for say, something less than the required amount of time, to actually build the upgrade, let's say it would take five years to construct the upgrade, but we only have a three-year contract with the customer.

If we request the capacity and the capacity's unavailable for the length of period or the length of priority that we need to serve that customer, but for a specific occurrence of a certain event or a specific number of hours, we may be willing to take the risk on that conditional firm service, just for that specified period of time, knowing that if this event were to occur, then we as a marketer would have to scramble and cover that contingency.

As a customer, as a marketer, what we do is risk mitigation. So it's a service that we can use to not only meet our existing conditions, but also to allow us to meet the conditions of other customers and provide a competitive product.

COMMISSIONER KELLY: Thank you.

CHAIRMAN KELLIHER: I wanted to ask Mr. Lucas about redispatch. Do you currently offer redispatch?

MR. LUCAS: Mr. Chairman, we do evaluate redispatch when we get a request for transmission service, if we've run across a circumstance where there are -- we determine when you run a transmission planning model against a request, you do so at various load levels. You don't do a planning model for 8,760 hours a year, but you pick some typical loads.

If we find a constraint, at the system study we would indicate there's a constraint. When we go to the facility study, we would then find the solution for that constraint and see if we had capacity available in our generation fleet that we could not operate and free up the contingency.

Again, some of the difficulties I pointed to earlier, reserve margins are slim and the bigger thing is the provider may in fact or any generator may in fact have to -- if you want 100 megawatts of opposing flow on a flow date, you may in fact have to redispatch hundreds of megawatts to get that 100 megawatt change of flow.

CHAIRMAN KELLIHER: So from the generator's point of view, in seeking service, when you do your redispatch estimate of some kind, is it that you can't -- the reason it might not be appealing from the generator's point of view is that you can't estimate how many hours of redispatch might be required or you can't estimate in advance what the cost would be?

MR. LUCAS: I think it would be both. You mean in terms of the challenge for the provider?

CHAIRMAN KELLIHER: Right.

MR. LUCAS: I think it would be both.

CHAIRMAN KELLIHER: You'd be saying we could accommodate you, we could redispatch, but we can't tell you how many hours or what it would cost you?

MR. LUCAS: Well, no. I think it's back to -- the challenge is already there today to offer the service. I don't think the challenge will change for the providers of are you going to be able to do that without impairing reliability.

The new requirement in the NOPR would be that as we evaluate that, we give an estimate of the cost and the hours. If we're able to do it, we would find a way if that was the final determination in the NOPR to give a projection for the cost and the hours.

CHAIRMAN KELLIHER: Well, when you say that -- okay, I don't want to confuse it with the bridge and conditional firms. Let me try to finish redispatch. I guess that was my question. Do you offer it -- well, let me ask the generators.

Is redispatch offered to the generators, and is it unappealing because of the uncertainty about what the cost would be? Is it the estimate, the lack of an estimate that makes it unappealing, or is it not generally an option available to you?

MR. TAYLOR: To my knowledge, it has not been an option that was generally available from a generator perspective. Going back to when I was on the provider side, at Entergy we did attempt to offer redispatch service to some customers who requested it, and we did not get very many takers because they were afraid of the cost.

They were afraid -- well, at that time, we did not give them all of the details concerning the contingency. So they were more concerned about the cost side of it.

CHAIRMAN KELLIHER: But there seems to be a question about how uncertain the costs are. At least Ms. Alexander doesn't think the costs are that hard to estimate, based on your paper --

MS. ALEXANDER: Calculate.

CHAIRMAN KELLIHER: Calculate. Would you say in many cases the cost of making longer-term service available using redispatch service would not exceed the average OATT cost rate?

MS. ALEXANDER: We in essence, certainly in our comments, put in an example, a numerical example of kind of the difference in the magnitude of estimated redispatch cost with a measure of error. You can build in a measure of error, not coming close to the cost of expansion.

If you're looking at a long-term transaction, if the customer's going to be paying the OATT rate for 20 years, then it's going to take an awful lot of redispatch cost to start having to bump up against that rate.

I would agree that estimating redispatch costs is a challenge. Calculating and verifying them shouldn't be, you know, on a real time basis.

CHAIRMAN KELLIHER: Verifying them after the fact?

MS. ALEXANDER: Uh-huh.

CHAIRMAN KELLIHER: Let me ask about the bridge, the bridge conditional firm. A couple of you have used that. I think Ms. McIntire and Mr. Lucas both said conditional firm should be a bridge. No? Didn't? You did.

I have it right here.

(Laughter.)

MS. ALEXANDER: I said it could be a bridge.

CHAIRMAN KELLIHER: Could be, right. You did say "could be," not should be. Mr. Lucas, I guess, said it "should be."

MR. LUCAS: Yes.

CHAIRMAN KELLIHER: Are you saying it should be linked to some commitment to pay for the upgrade?

MR. LUCAS: No, no, Mr. Chairman. Not linked to a commitment to pay for the upgrade. Linked to long term firm service that is requiring the upgrades. In other words, if the ATC is there, they should get the service.

It shouldn't be conditional. If we can't provide the service but for an upgrade being built, then that to me is the platform we should use for this conditional firm product. It's in connection with improving the system, so that next time around it won't have to be conditional.

CHAIRMAN KELLIHER: Ms. Alexander?

MS. ALEXANDER: And we think that many times that may be the case, that it is a bridge, long term transaction where expansion is the right economic choice, it should be built into the plans at some point when it becomes the right economic choice and the Commission's pricing will sort it out.

But it will often be the case that it will -- expansion would never the real economic choice. I think Commissioner Spitzer gave you an example of, you know, if it's only a few hours of redispatching, it's a minor cost and expansion is quite expensive.

It wouldn't be prudent to expand whether you're doing that for a native load or for your OATT customer, and we shouldn't take that off the table and have a rule that says it's only available for bridges. I mean I just don't get the sense of that.

MS. McINTIRE: It sounds to me like that's also the case for conditional firm. Sometimes it will be a bridge, but a customer might be very happy with having it at a period of time, and not having it all the time.

MS. ALEXANDER: Yes. At the end of the day, this will be an economic choice, whether to build or not. It should be an economic choice whether to build or not.

MS. McINTIRE: I would just like to add that there may be some situations where you have enough new generation or new interest in transmission where you can feasibly fund a whole new transmission line.

But there may also be cases where you just have a small project, and there's no way that that one project can justify that cost. But they might be willing to take conditional service or redispatch over a long period of time.

The other thing I wanted to point to is I think that we have two different concepts here when we talk about a bridge. One is the bridge to the time when new transmission is built and you get firm service, assuming you've paid to help fund those upgrades.

The other is a situation where you sign up as a customer for conditional firm or redispatch, when there is no ATC available, but at a later point maybe existing customers have not taken advantage of their rollovers, they've let their contracts lapse, and now there is more firm ATC available, and what should you do at that point.

I think Bonneville has an interesting solution to that, which at least the members of our organization have felt comfortable with. Do you want to mention that or --

MS. NICHOLAS-KINAS: I'm not quite sure which piece you're referring to. The way we would think about is if the customer did not choose to participate in the SIF and the SFS process, was given the option of just taking the conditional firm service in the long-term, that they would no longer be in the queue, per se, than to receive ATC that a customer may not have rolled over, for example.

But that if there was some larger upgrade effort that was open to folks, that they would have the opportunity, then, to participate in that.

MS. McINTIRE: I think I was recalling an earlier conversation that we had with Bonneville.

(Laughter.)

MS. McINTIRE: However, I think that Lauren's answer is also a viable solution for many customers. But Bonneville has been considering charging this product at their normal long term firm rate.

In which case if there is firm ATC that comes available at a later point, there's no incentive for a conditional firm or a redispatch customer to say "No, I don't want that firm ATC" and not to accept, you know, an upgrade to a full firm contract.

So that, I think, depends somewhat on pricing. But I think that that sort of a bridge is certainly a possibility for both of these types of products.

MR. TAYLOR: To Natalie's last point, there is the incentive for a conditional firm customer to upgrade to a firm product if that capacity becomes available, because it allows that condition to then be removed.

CHAIRMAN KELLIHER: I wanted to ask a question about, picking up on Commissioner Kelly's analogy, that 200 megawatts of firm capacity, the 80 megawatts of conditional firm and the one hour, and what if one hour becomes two.

Who gets curtailed? You just do a TLR? What effect would that --

MS. ALEXANDER: It would be pro rata, under the current NERC rules, unless you changed the rules in some way.

MS. McINTIRE: It would be pro rata, but I think you would be foolish for a transmission provider, if they saw that they needed one hour, to create a conditional firm product with just one hour. I think that all transmission providers are going to build in a conservative buffer there that's reasonable. But working with Pat's answer --

CHAIRMAN KELLIHER: What are numbers that Bonneville might be looking at for, you know, capacity? How much of your capacity might you consider offering as conditional firm?

MS. NICHOLAS-KINAS: It's going to vary by flow gate. What we'd like to have the ability to do is start off relatively conservatively, look at maybe a couple of hundred megawatts, get some experience with that, see how that functions with the various conditions that we've put around it, learn what we can because it's so new, and then move forward. If it looks appropriate, maybe broaden that out.

So we'd like to maybe be able to take a somewhat incremental approach. So the term "conservative," it's very much a balancing act between we want to be able to offer additional service, and we want to make sure that we're not doing something that would be detrimental to the existing customers on the system, or to the operations that we might not have foreseen.

So that that balancing act does cause us to want to be relatively cautious as we move forward.

CHAIRMAN KELLIHER: Thanks. From a generator's point of view, I'm trying to grapple with the either/or, both or neither kind of proposition, and I can understand in a hydro-based system, your view is redispatch isn't really an option, but you're exploring conditional firm.

But everywhere else, I haven't really heard anyone, not Mr. Lucas, no one say that we shouldn't explore either of these options or services, that they have certain challenges, but there's no reason just to rule them out altogether.

From the generator's point of view, is either of them more attractive? I think you both, Mr. Taylor and Ms. Alexander, said you like both services. You think they both should be offered. But do you think one is more valuable inherently than the other?

MS. ALEXANDER: I'd hesitate to say that, because it's kind of like a "it depends" answer, that you know --

CHAIRMAN KELLIHER: Conditional firm will be shorter term? I mean redispatch, I assume you could sign a longer-term contract. But then the difficulty will be estimating the hours, I suppose.

MS. ALEXANDER: Right.

CHAIRMAN KELLIHER: But it could be a longer-term contract?

MS. ALEXANDER: Each of them comes with different risks, as to who takes the risk, you know. In redispatch, the risk is a dollar risk. That may be uncertain. In the conditional firm, the risk is a curtailment risk that you don't have to hedge around and do something with.

You know, the opportunities to manage those risks may vary from transaction to transaction. So I hesitate to say that there's a rule that says that one is always better than the other, and it seems like the best thing to do is to incorporate both of them as options, get the information as to what can or cannot be done.

If both are available, then the customer can make an informed decision about what best suits that particular transaction.

CHAIRMAN KELLIHER: Mr. Lucas, from your point of view, is one riskier from the transmission provider's point of view than the other?

MR. LUCAS: I was going to ask you to be able to comment, Mr. Chairman. She outlined the risks, Pat did, for the generator. But for the provider, you've got the risk of trying to balance the reliability of the system and not being overly conservative in how many conditions or the types of conditions you would put on the service.

I think they're both of equal risk. It's a comparison of the risk of will you degrade or impair service to other firm customers by redispatching your own resources.

I think as I look at the two prongs, I see redispatch more risky, because if you're only talking about the provider's resources, if there's going to be an expansion of the market to drawn in other resources, will those resources always be available, how will be able to call on them, that kind of thing.

To me, there's a lot more risk there and questions there about how do you get that into something that's viable. On conditional firm, if we could work through a stakeholder process and lay out the conditions, I think the analysis is going to be the same. You're looking at is there capability in the wires to accommodate the transaction.

If not, could we put conditions on it and say in these periods, at these load levels, during these hours, it's not available. To me, that's a much more comfortable place to be if you're the transmission provider, rather than having to hammer through redispatch.

CHAIRMAN KELLIHER: From a transmission provider's point of view though, wouldn't the risk of redispatch be less if you could redispatch not only your own utility-owned generation but unaffiliated interconnected generation?

MR. LUCAS: Well, I think we'd feel better that it wasn't just our own resources being called to task. But I think you've just upped the complexity of having to take bids and figure out which resource was needed and is it available and so on and so forth.

COMMISSIONER KELLY: How many resources, network resources do you redispatch now in the Southern System?

MR. LUCAS: The fleet is well over 130-some odd resources. So I would imagine at any given time, all of those might experience some kind of redispatch. Probably some moreso than others. There will be at particular flow gates or possible constrained points on system.

COMMISSIONER KELLY: That's a lot of resources to manage now.

MR. LUCAS: Yes ma'am.

CHAIRMAN KELLIHER: Let me ask staff. Do they have some good questions? They don't have to be superb; they have to be good.

(Laughter.)

MS. AMERKHALL: I wanted to go back to this discussion --

CHAIRMAN KELLIHER: Your mike on, Jennifer?

MS. AMERKHALL: Yes. I want to go back to the discussion about the customer, the conditional firm customer firming up once firm becomes available, and I think this is very related to whether conditional firm is bridge service or not.

But in certain situations, you might have a conditional firm customer get service, say 100 megawatts of service, and then along comes the next customer who doesn't want to take conditional firm service, but is willing to pay for the upgrades. What happens in that situation? Who gets the firm service if the conditional firm customer has like right of first refusal?

MS. NICHOLAS-KINAS: Well, the way we're thinking about that is that that conditional customer would retain its conditional characteristics, and that they would probably be called upon less for conditional curtailments for a time before that additional ATC -- because ATC is lumpy -- actually gets sold.

But that additional ATC that they didn't then participate in funding would be posted as ATC that would available to be sold to other customers.

MS. AMERKHALL: Any other thoughts on that?

MR. TAYLOR: From a transmission customer's perspective, if we were to purchase the conditional firm service and some other party were to come in and actually pay for the upgrades, from our perspective it's so long --

well, our service would remain conditional, up until -- well, our service will remain conditional, subject to the conditions that were defined in the TSA.

Therefore, the customer that actually paid for the upgrades or paid for the firm service, his service would be firm. If at some point we decided to pay for the upgrades, then our service would then graduate to firm service, traditional firm service.

MS. AMERKHALL: But what happens if that second customer in line creates firm service for you and by your taking, your being first in the queue for that firm service, you take away from that second customer?

MR. TAYLOR: I would say that we would remain -- again, our status would remain the same. What would happen would be that the set of conditions that were identified, assuming that that second customer had the same set of conditions identified in their system impact study, then by virtue of that second customer performing those upgrades, then that second customer would lessen the likelihood of those conditions actually occurring. But that first customer would still be subject to those conditions if they did occur.

MS. AMERKHALL: And the problem that you outlined of the customer being first in the queue for the new ATC can be handled, by not allowing them to stay in the queue if they're not interested in financing a build?

MS. NICHOLAS-KINAS: Jennifer, the lumpy investment situation that you just presented, it happens today in the other order. One customer bites the bullet and builds the upgrade, and it's lumpy. The next customer comes along and doesn't have to build an upgrade.

All right. So we have that today, and I don't know why we'd want to treat a customer who happened to select conditional firm any differently and say because you came first instead of second, you don't get the advantage of the lumpiness.

You know, if you're going to fix lumpiness generally, you'd have to fix it in all the scenarios that it happens in, not just the conditional firm situation. If you have an issue with somebody coming along second and getting the benefit of an upgrade funded by another customer, deal with that generally and apply those same rules to conditional firm.

MR. LUCAS: Jennifer, could I -- I think you've raised the perfect pricing horror that could come out here, if we don't consider linking this or creating it as a bridge product. I think the bridge product solves that, is that the first customer in the queue, he's waiting on the upgrade.

So there's something being built for him. If we don't have that bridge feature in there, then I think what you've created is if Customer 2 comes long and he drives an upgrade that will firm up Customer 1's service, and the upgrade would have driven the higher of pricing.

In other words, rolling it in would not be the lower cost. I think you're going to have both customers brought back to the table and spread that incremental cost between the two of them. To me, that's only fair, and I don't think the first conditional firm customer would be very excited about that.

MS. McINTIRE: I think this is a challenge. My sense is that Bonneville has a solution that may be workable. Anthony says that as a customer, they would be willing to maintain conditional firm service.

But I think what absolutely does not work is for a customer to sign up for a conditional firm product, and then five years later be told oh, you're going to have to pay $30 million or $50 million because we're doing this upgrade, and they haven't factored that into their balance sheet.

All of the sudden their project is no longer -- doesn't make money. They're not going to be happy. Because of that, I mean I think it's really important that this could be used as a bridge product if at the time of a contract, there's enough interest to build that new line.

Then you can say "Well, you know, we're going to build this new line. Everyone's going to sign up to fund a portion of it, and then we're going to have the line five years down the road. But you, wind project, you're going to be on-line next year, you know.

"You can take conditional firm service until that time. But if you don't have enough interest in the line, you lose the opportunity to make some use of the system for that period of time."

You know, it may be a significant period of time until you have enough interest to really fund the line.

MR. LUCAS: Just one quick follow-up. Natalie's raised a great point. But I think the challenge here, and we've got to recognize, upgrades may in fact not drive ore pricing. So it may be an upgrade that could be done and not rolled in and you wouldn't have the issue of customers having to fund projects. They would just be paying the normal transmission rate. So I don't think it always goes automatically to having to fund incremental improvements.

CHAIRMAN KELLIHER: Great. Any other questions?

MR. HEDBERG: Do all the panel members agree that a conditional firm product should be eligible to be designated as a network resource? Are there any reliability concerns regarding that?

MS. NICHOLAS-KINAS: We have spent some time trying to think about how conditional firm or something akin to that, some way to take that ATC and make it available to a NT customer, could work. We have not been able to do that out in a way that we would be able to answer that question yes or no at this point.

I think that that would need maybe substantially more discussion before we could come to a clear understanding of whether or not that would work.

MR. HEDBERG: How about the flip side of that question? If it is not eligible as a designated network resource, is there interest in it by the wind folks or Williams or a marketer or any other transmission customer? Is it contingent on it being eligible as a designated resource or there's no interest in it?

MR. TAYLOR: From our perspective, I think we're interested regardless.

MS. McINTIRE: I think there is interest. There's also the other potential, which is that using this product to wheel through one transmission provider service territory to get to another. Then that second transmission provider, their network load, is wanting to designate it.

I think in that case, it really must be potential for it to be designated as a network resource. I don't think it's that much different than a firm contract right now, which could be curtailed, you know.

Any network resource that has a firm contract has a potential that in any particular hour it could be curtailed. But that doesn't remove the possibility to designate it as such.

MS. ALEXANDER: It also seems to me that a lot of network resources aren't available 8,760 hours a year. There's forced outage rates on thermal units; there's intermittent resources, the wind is blowing or not. If they get designated as network resources, there could be air improvement issues.

So I mean the notion that a network resource that doesn't have firm guaranteed access every hour of the year shouldn't be designated as a network resource, we don't do that today.

So there's got to be a way, if we can get comfortable with the conditional firm product, that is defined one, the customer's not going to take it if it's going to be interruptible nine months a year. They're just not going to take it.

That why wouldn't we let that be a network resource, just like other types of network resources that have these kinds of variations?

CHAIRMAN KELLIHER: Kathleen?

MS. BARRON: One more question.

CHAIRMAN KELLIHER: Sure.

MS. BARRON: One of the things I think the Commission has been struggling with is if conditional firm is a product in the tariff, shouldn't it have the same level of detail in the terms and conditions as the other types of products in the tariff?

So we focused on should the conditional part of conditional firm service be a number of hours in which the product is conditional? Should it be conditional on the load levels or system conditions?

So we've had some discussions on this point in outreach meetings and such. I haven't been surprised and I'm not surprised to hear Mr. Lucas say that we should let the transmission provider figure out which one of those might work best and offer it in the particular circumstance of the customer.

But I think I heard Ms. Alexander and Mr. Furman make the same point, that just because hours or contingencies doesn't work on a particular system, that's not a reason to arbitrarily eliminate the product altogether.

So my question is, when you two talk about flexibility, is it in the nature of what Ms. McIntire suggested, of let's do this in a collaborative way or let's let folks get together and talk about it, or are you suggesting that the tariff might let flexibility exist, such that the customer and provider would work it out?

MR. FURMAN: When I made my comments, it was -- if I wasn't articulate about it, let me try again.

It has to be done with standards. The tariff has to have standards in it, and the devil's always in the detail. But I wasn't -- I did not mean to suggest that we just send people off to collaboratively look at how we put this product together. I think there has to be some specific guidelines and standards that say --

And it may be that, you know, that should be that we have to operate a couple of different ways. But I do think there is room for optimization between the transmission provider and the transmission purchaser, to get a better deal, a win-win situation, to use the cliche.

So I think you want to have some flexibility within those standards. Now you're going to ask me what standards, and I don't know.

(Laughter.)

MS. ALEXANDER: I agree. We have to have some level of standards in the tariff, that will at the same time provide flexibility for multiple options to consider transmission service requests.

That's, you know, one of the other challenges we're facing is how do we accomplish that, because it sounds kind of contradictory. You know, the more you micromanage it in the tariff, the less flexibility you give the transmission providers.

The less you micromanage it in the tariff then, you're back at the same setup, where you've got complaints well, they're not being fair in what they're offering us. So we have to figure out what the right balance is on that. But there has to be sufficient teeth in the tariff to kind of describe major principles, major classifications of the types of things that need to be done and how they'll be done.

But in any given transaction, it could be, you know, two of those options may be off the table because it's just not workable for that transaction.

MR. HEDBERG: Does that mean that you'd suggest a menu approach in the tariff, that there be a menu of conditions that could be identified, or would you suggest that the stakeholder discussion group, if we go that way, should narrow down the list of possible contingencies?

MS. ALEXANDER: I think that's what we should do, really. You know, I hesitate to say a menu, because a menu could end up not having something on the list that you want, and it's going to be difficult for everybody to agree on the menu.

So it may be at a slightly higher level than that, in terms of definition. But I think it's something that getting together a group of people to try and see how it works when you start to write it down and what you try to commit to, and see what could end up in the tariff and be actually workable would be a good use of our time.

MR. LUCAS: One follow-up real quick, Lenny. If I implied I didn't want that to be a collaborative process, I didn't mean to. I meant providers and customers. I had hoped that's the way it came across.

CHAIRMAN KELLIHER: Do we have any other staff questions? Jennifer?

MS. AMERKHALL: I think this will be very quick. I'm looking for consensus on the NOPR about conditional firm, and I think I heard at least two areas of consensus. Does everyone agree that the conditional firm service should be charged at the long term firm point to point rate?

MR. LUCAS: You asked for agreement. I'll say yes, I agree with you.

(Laughter.)

MS. AMERKHALL: I see a lot of nods. Okay.

MS. ALEXANDER: The one caveat is if you are going to -- going back to our discussion about conditional firm not being able to be converted to firm if capacity happens to become available, then I'm not sure that it's fair to charge them the firm rate but to say that unlike other firm customers, they don't get the benefit of lumpy upgrades or whatever happens on the system.

MR. TAYLOR: The other consideration would have to be that for the actual occurrence of the condition, then the customer is not receiving service during those hours. So therefore the customer should not be treated as a firm customer during the hours where they're actually interrupted or not allowed to flow.

Because at that point, that customer actually converts over to more like a non-firm customer.

MS. AMERKHALL: So you're saying you wouldn't be willing to pay the long term firm rate to get that service?

MR. TAYLOR: It should be charged at the long term firm rate, but for the hours where there's no service provided.

MS. AMERKHALL: So refunds on those hours?

MR. TAYLOR: Credits, however you want to do it.

MS. AMERKHALL: Okay. So you're not willing to pay the long term firm rate to get the service?

MR. TAYLOR: Yes, we are.

(Laughter.)

MS. AMERKHALL: My second area -- I hope there's a little more consensus on this. I'm sorry, Natalie. Did you want to --

MS. McINTIRE: I just wanted to follow up on that, because it was a discussion that we had through our process at Bonneville. That was the original suggestion that we gave to Bonneville.

I think it's helpful for the discussion here to know that the firm customer said wait, that's better than what we get. If we get curtailed, we don't get any credit. So it seems to me if that's the direction to go, you need to make sure that you're going to at least give that same sort of treatment to firm customers should they get curtailed.

MS. NICHOLAS-KINAS: One of the issues or ideas that we'd like to further explore, and maybe try to get systems in place for, would be to give those customers essentially automated bites to any short-term firm ATC that would become available, as opposed to trying to do something else.

So that we wouldn't sell additional short term from ATC unless their conditional firm reservations were able to firmed up for that period of time.

MS. AMERKHALL: Thank you. That's it.

CHAIRMAN KELLIHER: Thank you. Colleagues, any other questions? I think we have five minutes for the audience. We said time permitting, we would entertain any comments, hopefully questions from the audience. If there are none, we could leave early.

(Laughter.)

CHAIRMAN KELLIHER: So this is your last chance.

Anyone in the audience want to make a comment?

(No response.)

CHAIRMAN KELLIHER: Okay, thank you. I just want to say I want to thank all the panelists. I think the quality of the presentations was very high. I want to thank the staff and I also want to thank my colleagues.

The fact that we were all here today all day long, I think, shows that we recognize the importance of what we're doing. Thanks for your help.

(Whereupon, at 3:56 p.m., the meeting was adjourned.)