BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Numbers:

TECHNICAL CONFERENCE ON SEAMS ISSUES : AD06-9-000

FOR RTO'S AND ISO'S IN THE EASTERN :

INTERCONNECTION :

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Hearing Room 2C

Federal Energy Regulatory Commission

888 First Street, NE

Washington, DC

Thursday, March 29, 2007

The above-entitled matter came on for technical conference, pursuant to notice, at 9:10 a.m.

BEFORE:

JOSEPH T. KELLIHER, Chairman

FERC COMMISSIONER

APPEARANCES:

COMMISSIONERS PRESENT:

CHAIRMAN JOSEPH T. KELLIHER

COMMISSIONER SUEDEEN G. KELLY

COMMISSIONER MARC SPITZER

COMMISSIONER PHILIP MOELLER

P R O C E E D I N G S

(9:10 a.m.)

CHAIRMAN KELLIHER: Good morning. Why don't we close the doors? I didn't mean to interrupt Commissioner Kelly's greetings. She was greeting the panelists, so, very good manners.

Good morning. Welcome to the Technical Conference on Seams in the Eastern Interconnection. And as the last Easterner at FERC, I have a special interest in this proceeding.

(Laughter.)

CHAIRMAN KELLIHER: If my colleagues have a more -- have more of a distance with them from the Eastern Interconnection. Other colleagues will be joining us a little bit later, but one thing I've noticed, is that if you don't start technical conferences, they don't end, either, so we're starting a little bit late, but not too late.

Now, the United States does not have a national electricity grid or national power grid. Instead, we have a series of regional markets and regional grids, and there are significant differences among these regions.

Some of the differences relate to market structure. Some regions have adopted the organized market structure, establish day-one or day-two regional transmission organizations, and some other regions have not.

The Eastern Interconnection has both market structures. At one point, it was thought that the organized market structure would extend throughout the Eastern Interconnection, and that there would be fewer larger RTOs.

That vision offered the promise of fewer seams among the regions in the Eastern Interconnection. But that vision is no longer the common expectation.

That has implications for Commission policy, since there is significant trade among these regions. There are seams in the eastern power markets, there are seams among the RTO markets; there are also seams between the RTO markets and non-RTO members.

Now, given the structural differences in these markets, it's probably unrealistic to expect that we will be able to eliminate seams in the Eastern Interconnection, and I, personally, would rather not pursue an impossible goal.

So I would submit that what we should be doing, is concentrating our efforts in identifying the market seams in the Eastern Interconnection that create the greatest barriers to trade and costs shifts in developing proposals to address those seams.

I think that if we focus our collective efforts on the world of the possible, we can do some good. Now, there's no reason to think that that goal is unattainable.

We've made a lot of progress in reducing seams in the Eastern Interconnection in recent years, and I would point to the MISO-PJM Joint Operating Agreement; the MISO-SPP Joint Operating Agreement; the MISO-MAPP Core Seams Agreement; and the MISO-PJM-TVA Reliability Agreements, as examples of how parties can work together to successfully address seams issues.

Now, I urge the parties to work together again and help us identify the market seams issues that cause the greatest burdens on trade and cost shifts.

Now, I also ask you to go one step further and offer your ideas on how to resolve these seams issues.

Now, this Conference, if you will recall, started with a much more modest scope; namely, examining the free-rider issue as it relates to ROT border utilities, and although the scope of the Conference has expanded, I want to make sure that no one draws the wrong conclusion.

Personally, I think the free-rider issue is a legitimate concern. The Commission's policy promotes voluntary RTO formation, and I, personally, support voluntary RTO formation, and our competition review is focused, in large part, on reforms to improve RTO markets.

However, if RTO membership is voluntary, then members must have some ability to withdrawn. Our Order in Louisville Gas and Electric Company, shows that we honor contractual withdrawal rights.

However, a policy should not provide an incentive to RTO members to withdraw, and we must examine ways to address the issues associated with non-members who use RTO markets.

Now, we have a lot of ground to cover here today, and I want to thank the panelists for helping us, for being here, and I look forward to hearing your views. And I'd just ask my colleagues if they would like to make an opening statement.

Commissioner Kelly?

COMMISSIONER KELLY: Thanks, Joe.

CHAIRMAN KELLIHER: You were born in the East, so you have an interest in the Eastern Interconnection, too.

(Laughter.)

COMMISSIONER KELLY: Thank you very much. Whenever I can, I try and claim heritage on both sides of the Mississippi.

(Laughter.)

COMMISSIONER KELLY: Whenever you try and create something, whether it's out of textiles or plastics or metal or market structures, you create a seam.

There are lumpy seams; there are flat seams; there are French seams; there are ornamental seams, but there are also invisible seams, and in textiles, in plastics, in metalwork, we created -- taken advantage of advanced technology to make invisible seams.

So, for sure, we're going to have seams, when we create a market structure, but let's see if we can't make them invisible. Thanks very much for being here today to let us know what the areas are that we have to work on, and for giving us some suggestions for the advanced technology that we can use to make those seams invisible.

CHAIRMAN KELLIHER: All right, thank you. That was spoken as the resident scientist on the Commission. Thank you very much. It was very impressive.

COMMISSIONER KELLY: Thank you. And seamstress, too.

(Laughter.)

CHAIRMAN KELLIHER: I'd like to now recognize Commissioner Spitzer.

COMMISSIONER SPITZER: Thank you. I am not a seamstress.

(Laughter.)

COMMISSIONER SPITZER: And the seams conference in the West, in Phoenix, was an interesting dry run for this conference, and I would suggest a few things:

First, I am a native of Philadelphia, so if we all want to claim some nexus with this issue -- I really value the materials that were submitted as part of this. It's not often that you get such detailed filings that narrowly focus in on the specific issue, and some of the filings were extremely, not only narrow in focus, but offered solutions and resolutions, which I find extremely helpful.

If I could generalize, the western seams were largely a product of climate. You've got hydro in the Northwest, that colors the entire Western Interconnection; great expanses, so that geography is important; isolated load pockets; transmission reflecting the fact that load pockets are located far from the generation sources, so it's an entirely unique set of circumstances, again, largely geographical and climatic.

Whereas, in the East, the circumstances are largely historic. I'm a student of history was in my past and try to continue to follow it, and so you've got these tight power pools, but yet historical demarcations and distinctions, in many cases, based on very sound business practices, but there's been evolution over time, and I think what the parties are trying to come to grips with, is how to resolve some of these historic divergences among and between RTOs and ISOs, in a way that reflects the legitimate historical bases for these original setups, and doesn't do any damage to business practices or economics.

So I find this topic very interesting, and look forward to further discussion, particularly as we hone in, again, on some of the precise proposed solutions and resolutions to these issues.  I very much look forward to this day.

CHAIRMAN KELLIHER:  Great, thank you, Comissioner Spitzer.  When our colleagues arrive later on, we'll give them an opportunity to make an opening statement.

But before proceed, I just want to commend the Staff.  I really think the briefing book was first-rate, and particularly the briefing paper.  I really enjoyed the briefing paper.  It was really first-class, so I commend you for that.

And I see it's from the Staff Team, so I can't single out -- I don't know who, actually, was the primary author, but I just want to commend the Staff for the briefing paper.

I just want to recognize Kevin Kelly, to day is his birthday, and if we could have some applause for Kevin on his birthday.

(Applause.)

CHAIRMAN KELLIHER:  So, why don't we start with our panelists?  We may interrupt you when colleagues arrive, but let's start with Stephen G. Kozey, Vice President, General Counsel, and Secretary with the Midwest ISO. Welcome.

MR. KOZEY:  Mr. Chairman and Commissioner, thank you for your decision to convene and take part in this conversation. My company is interested, because developments following the conversation, may eventually adjust the balance of burdens and benefits associated with membership in the Midwest ISO.

My pre-submitted materials address our formal agreements with neighboring entities, however, toady, I will address circumstances where we believe border utilities receive benefits from their neighboring RTO, but pay disproportionately less for them than the companies in the RTO.

The conversation will certainly not conclude today, but I think it will warrant your continued attention.

Some believe that the best place for a vertically-integrated utility to be, is just outside an RTO. If transmission owners perceive that they can secure most of the benefits of an RTO, while avoiding full cost responsibility, that's what they will do.

This places increased costs on members of the RTO, which works as a disincentive to continued membership.

I will focus on three areas: Market, reliability, and other economic inequities.

The Commission has not yet been convinced that one particular market inequity warrants imposition of a reciprocal requirement.

RTOs present their border utilities with a 24-hour-a-day, real-time energy market that stands ready to purchase from all comers at posted, transparent prices reflective of spot market conditions.

Border utilities can and do sell energy into organized markets, without making a reciprocal commitment to purchase energy at a posted incremental cost.

This difference sets a hurdle for generation asset owners in the RTO wishing to sell out, that border utilities do not face. Mr. Ott from PJM will address this issue in more detail, and we generally support his remarks.

I will address two reliability inequities: One relates to spillover benefits from investment in tools and systems; the second relates to loop flows.

RTOs have short-term reliability and congestion management responsibilities. NERC requires reliability coordinators to have a wide-area view that encompasses their neighbors.

To meet these requirements, the RTOs have developed sophisticated tools and systems. In the Midwest ISO's case, our state estimator receives data from nearly 200,000 points, about 120,000 of which are from outside of our footprint.

Our systems produce a five-minute dispatch signal that takes into account, the results of approximately 7,000 what-if contingencies every five minutes.

Not all reliability coordinators have invested in the same sort of systems. When a reliability coordinator for a border utility does not have a similar system, the Midwest ISO often knows of developing conditions sooner than the other reliability coordinator.

We do alert the affected area, but neither the Midwest ISO nor its members, are compensated for the value of the systems by those outside the RTO.

Secondly, loop-flow issues still present reliability and economic challenges. One challenge occurs when a border utility sells to either PJM or the Midwest ISO.

There will be flows on the purchasing RTO's system and on the bystander-RTO's system, as well. RTOs were intended to decrease the commercial and reliability problems associated with loop flows, by internalizing them.

They have for dispatch within their borders. In addition, PJM and the Midwest ISO, have done so as between themselves, through detailed operational coordination.

However, experience has taught us that there are substantial and often largely unpredictable flows from parties outside our system, that do affect our operations.

They can contribute to commitment of peaking resources, and limit our redispatch flexibility and efficiency.

As long as parties on our borders do not upload the same flow data to the NERC IDC, as several of the RTOs do, our market participants suffer an inefficiency that is due mostly to an information disparity.

There are other economic inequities:  Payment formulas currently in place to recover the Midwest ISO's cost of running its market and this Commission's annual costs, each make being a border utility, less expensive than being in the RTO.

The Midwest ISO recovers about $105 million annually for operations of its  $23 or $24 billion a year energy markets.  It also recovers just under $30 million of this Commission's annual operating costs from companies within the RTO.

We propose that an examination of a change to both assessments is appropriate.  Today a border utility pays to support the market, only on megawatt hours sold into the market.  It receives the benefits of the market's availability and low entry hurdle, but pays a disproportionately low portion of the cost to maintain the market, than RTO members.

Similarly, because of the current assessment of the Commission's operating costs, utilities outside RTOs, pay only on transactions the Commission considers jurisdictional.

For the border utility, no generation injected to serve bundled load, is counted, so these companies bear a smaller proportional share of the Commission's costs than the same utility would, if it were to join an RTO.

More painfully, to the nonjurisdictional municipal and cooperative transmission owners in our RTO, they would pay nothing at all, at least directly, to the FERC, if they were not in the Midwest ISO.

Because the Commission's internal organization and its approach to carrying out its regulatory duties have changed since the time this was last considered, and because of commitments noted in Midwest ISO vs. FERC by the D.C. Circuit in 2004, we would urge you to have an open ear as we more fully develop this point and bring it your attention in the future.

Other inequities and unsolved problems, include: The spillover benefits of regional planning in an RTO; reliability and economic benefits from the transmission upgrades called for in a regional plan to ensure reliability or to produce more effective competition, will often spill over to utilities not making the investment in such facilities.

Thank you, and I look forward to your questions.

CHAIRMAN KELLIHER: Thank you very much. I'd now like to recognize our colleague, the Honorable Kurt Adams, the Chairman of the Maine Public Utilities Commission. Welcome.

MR. ADAMS: I don't get to be on this side of the bench very often.

(Laughter.)

MR. ADAMS: Thank you Mr. Chairman and members of the Commission. My name is Kurt Adams, and I'm Chairman of the Maine Public Utilities Commission.

I'm truly honored to be here with you today for this very important topic. Portions of Maine are part of the New Brunswick Control Area, and are not electrically interconnected to New England.

Other parts of Maine are connected to New England and have been so for 30 years. We are, in many respects, a border state for two separate control areas: One with a sophisticated organized market and one with a developing market.

The seams issues, which is what I will speak to principally today, the broader topic, Mr. Chairman -- and I think it's appropriate and wise to have expanded the topic to encompass a greater range of issues, and that I was unaware of when this Technical Conference started, is particularly important to us.

There is one category of seams that you covered -

- that you left out of the list that you covered, and that is seams within RTOs. And within the New England RTO, there are seams within it, and they take two different forms. I'll talk about that in a moment.

First, the Maine Commission, as a Commission, and me, personally, as an energy lawyer prior to my job here on the Maine Commission, have advocated for a long time, for centrally-organized large markets, with as few seams as possible.

We have believed, philosophically, that they, if structured properly, produce the best benefits for consumers, with the greatest options for buyers and sellers, but the key is the voluntary nature of the agreements.

This is not a legal conference today, so I won't get into what we believe the legal position is. I believe you covered it fairly well, Mr. Chairman.

But the voluntary nature of buyers and sellers coming together and transmission owners coming together with their 205 rights, really does, in my view, define what an RTO is and what it should be, and what the exit terms ought to be.

But on organized markets, it's fascinating to be back in this room to talk about seams, because in the Summer of 2001 -- and, for me, that was two jobs, 15 pounds, and two children ago -- I spent six weeks here with many of the very same people, talking about this very same topic.

And it was a very well-run and detail-oriented Summer mediation ordered by the Commission on seams, specifically between PJM, NYSO, and then the ISO New England RTO.

What we discovered in that process, is that there was a great deal of information that the RTOs had never shared before, and it created, in my view, a platform that has continued in terrific coordination between them.

But what it also elucidated for me, is that there is no common definition of what a seam is.

Seams too often are characterized as the culprit or the cause of prices not converging between markets or within markets. If prices don't converge, because somebody is artificially creating a barrier to trade, for instance, if somebody is driving prices up in a region where they are a seller, or down where they are a buyer, it creates dynamics that have to be addressed through typical market monitoring or transmission investment mechanisms, principally because it creates uneconomic allocations of resources. It's not economic for those seams to exists.

But there can be a number of legitimate reasons why prices do not and should not converge, and there are instances when we force prices to converge, perhaps in the name of eliminating seams, where prices should not converge.

In that case, by making them converge, we create a problem and not eliminate them. And I'd like to give you one brief example of what I mean by this.

In New England, we have locational marginal pricing, and there is price separation between Maine and the rest of the pool -- not an enormous amount of price separation. Congestion accounts for around a four-percent difference between Maine and the rest of the pool's locational prices.

Maine, today, under the existing transmission cost allocation rules, has no incentive to eliminate that four-percent price differential, to eliminate the seam. In fact, with a thousand megawatts of wind on the drawing board in Maine, Maine has a powerful disincentive to eliminate that seam.

Under the current transmission cost allocation rules, Maine would have to pay a portion of new transmission to eliminate that seam and thereby pay for the privilege of having its rates increased. That seam, creates incentives on both sides of Maine's border to the south.

At the seam to the south, there are loads who would like to see the seam relieved, and in-merit generation to be able to reach the pocket, but the system doesn't work right, as it is currently configured, because the incentive for Maine does not exist to fix the problem.

Now, fixing it through transmission cost allocation reform, is certainly an avenue that might work, but an avenue that might also work, could be withdrawal from the RTO.

If there was -- and there currently is -- approximately a thousand megawatts of new generation in Maine, and perhaps more in New Brunswick, that could be brought online, the types of generation that ISO New England and other market participants believe that the New England system desperately needs, non-fossil-fired baseload generation, could be brought to the market, all consumers could win.

But under the current dynamic, we have a circumstance where New Brunswick consumers might win, southern New England consumers might win, but Maine might lose.

If Maine withdrew from the RTO and created a seam, which I refer to as an economic seam, to pay for some of the costs of the infrastructure to transfer the energy from these potential resources, then all consumers benefit.

If the seam within New England is driven to be open through, say, federal preemption, the seam would be eliminated and power would flow south, but you would immediately create an economic distortion within the RTO that favors remote generation over generation in load pockets.

So, there's a circumstance within New England today, where what a seam is and whether or not a seam is a good thing or whether or not a seam is a bad thing or whether or not it's economic and whether or not it creates the right incentives, that's wildly complicated, and very, very technical in how it impacts the decisions on either side of the various borders within Maine and New England.

So, for us, when we think about the issue, I think about what, exactly, a seam is and what it means to open the market. And our basic view -- and this is just a comment in closing -- the Maine Commission's basic view is that seams are really just a boundary of an economic relationship, and there is statement of an economic relationship, in some cases an operational relationship, but, most of the time, an economic relationship.

And if the economic relationship is going to be reformed, it ought be reformed to the benefit all of the consumers, not just a discrete portion of the consumers on either side of the significant interface.

And as the Commission grapples with the issue of what a seam is and how to change a seam or how to modify a seam or how to create a seam, my suggestion would be that the Commission focus on how to make markets bigger, how to bring more resources into the market, as opposed to simply change the cost allocation or change the individual benefits or costs of market participants, a group of market participants within an existing system.

There you can be guaranteed that the RTO will deliver to all consumers, the maximum benefit, which is what I believe their ultimate charge is.

Again, thank you very much for having me here today, and I really appreciate the invitation.

CHAIRMAN KELLIHER: Thank you, Chairman Adams. I'd just like to now recognize our colleague, Commissioner Moeller, and see if he'd like to make an opening statement. I will also explain that at some point today, if he gets up and bolts out of the room, it may be that he and his wife, Elizabeth are having a baby, so don't be alarmed.

(Laughter.)

CHAIRMAN KELLIHER: Two babies. Sorry I forgot.

(Laughter.)

COMMISSIONER MOELLER: I'll make my comments during the course of the conference, but I appreciate all of the panelists for being here, for making the significant effort, for what's set to be a great set of discussions, and build on our Phoenix conference, which was extremely productive back in December. I'm looking forward to all the comments today. Thanks for being here.

CHAIRMAN KELLIHER: Thank you. I'd like to now recognize Andrew Ott, Vice President for Markets in the PJM Interconnection.

MR. OTT: Thank you, Mr. Chairman. Thank you for the opportunity to speak in front of you today.

PJM understands that there will be different market structures, market and non-market structures in the U.S. for some time. And the fact that you'll have these differences that will create seams, is not, in and of itself, harmful.

But the issue we need to focus on, though, is the existence of seams that are, in fact, harmful, cause disruption, and cause inequities, so while we absolutely agree that just the existence of seams itself, is not bad, what we need to focus on, is those that are, in fact, bad.

I'd like to speak today about several of these seams that we see as harmful.

The first is the increasing issue of loop flow, and this will be the issue on top of my list. All of us who operate control areas, have experienced this loop flow, and to some extent, in the Eastern Interconnection, we've decided we're just going to live with it, historically.

I think the time has come that we need to face the reality that loop flows need to be dealt with. PJM has had unhappy experiences with increasing loop flow.

I had to sit in front of my stakeholders, the

City of Chambersburg, and tell them, essentially, they got less transmission rights because or partly because of loop flow, so the issue is real; it's not theoretical, and it does create issues.

PJM and MISO have recognized that we create -- our markets create flow on other systems, and we stood up and said that we need to make sure to take care of those flows. We've implemented market-to-market coordination processes, and not only that, we actually calculate the impact of our generation-to-load dispatch flow on other flowgates -- not market flowgates, but other flowgates -- and report them to the NERC IDC, every 15 minutes.

So, essentially, we have stepped forward and tried to account for our flows on a real-time, accurate basis, and we report those. We have worked with others and we would invite anybody who thinks that flows appear on their system from our markets, to let us know and we certainly will deal with that issue.

We understand we have this obligation to our neighbors, but our problem is, the neighbors, if you will, aren't stepping up and seeing the same level of flow accountability.

There are two sources of flow: The first is the control-area-to-control-area transactions that occur; and the second is the generation-to-load dispatch in control areas around the Eastern Interconnection.

Neither one of those flows are tracked accurately. For instance, in the NERC TLR process, any flow from control area to control area, below a five-percent power transfer cutoff, is virtually ignored, and, essentially, that can amount to a lot of flow.

My colleague, Mr. Kormos, will talk about that later, about the details of how that affects operation. So those -- while, in the past, it may have been good enough to say anything greater than five percent, we'll look at and anything less, we'll just live with, that is no longer really acceptable.

And the other issue is the real-time nature of generation-to-load dispatch is really unaccounted for at this point, outside the RTOs, and that needs to be dealt with.

Again, we can't solve the issue unilaterally, but, obvious, as the Chairman had mentioned, we are trying to reach out and create solutions.

In efforts to seek cooperative relationships, though, we have looked at trying to get data to identify our own loop-flow problems. That has been, to say the least, a painful experience, to try to gather the amount of data we needed in real time, to quantify what is actually happening.

It took us five months. I think we had to sign six or seven confidentiality agreements, just to get data to figure out what's flowing on the system. The Commission could certainly help in trying to make that process easier for us to gather the data we need.

I'd like to move on to a second issue, which involves external transactions selling into an RTO, and essentially getting the RTO spot price, LMPs based on actual flow, rather than contract path, as you know, and the practice of paying these locational prices to contract path customers selling into our market, has become increasingly harmful to RTO customers.

The RTOs have identified and attempted to correct the problem as we changed our interface pricing definitions, but, again, I can't do this unilaterally.

The fact is that external parties don't provide appropriate flow data to us in order to allow us to calculate an accurate price. So, in short, it's not fair that PJM customers should pay spot price through external transactions when their flows can't be validated to the same level as the RTO customers' can.

The RTO customers provide all the data for us to accurately calculate what they should be paid, therefore, PJM believes that external customers selling in, that are not backed by accurate data, shouldn't have access to the be paid the spot price.

I'm not saying they shouldn't have access to the market, but they should contract bilaterally, not get the spot price that's calculated based on actual flows.

I'd like to turn to another issue involving equity, which, again, deals with the issue of not allowing an unintended incentive for border utilities.  This comes down to, again, the issue of flows.

If you have utility that was in an RTO, has generators to load, those flows are properly accounted for, because we see the generation and the load dispatch every five minutes.

If that utility goes out of the RTO, then they start reporting their flows, again, on a control-area basis; the generation-to-load flows are no longer accounted for, okay?  So they can sell in now to the RTO and potentially ignore very harmful flows that they may have had to face in the past.

And that's an issue that has nothing to do with administrative fees or, necessarily, free-ridership; it's essentially saying that the level of granularity they used to have to face, they no longer face.  That's an inequity that creates cost shifts and needs to be dealt with.

The last -- there are broader issues involving free-ridership, et cetera, that I will not cover today.  I had also given you an example, too, that I can't cover in this time period, but it helps you to understand the sources of some of these loop flows, and discusses the nature of them.

Again, the issue here, okay, is, yes, some flows are measured in the Eastern Interconnection, but they aren't being measured in real time and they aren't being measured accurately, and the five-percent cutoff that is now a NERC standard, okay, is a problem and we need to account for it.

If you have a thousand megawatts flowing at four percent, that creates a substantial amount flow, so the volume of flow we have in the Eastern Interconnection, needs to be accounted for and we need to deal with the issue.

Again, I appreciate the opportunity to talk to you about these issues today and I look forward to your questions.

CHAIRMAN KELLIHER: Thank you. I'd like to now recognize Michael Beer, Vice President of Federal Regulation and Policy with E.ON U.S.

MR. BEER: Good morning, Mr. Chairman and Commissioners. Thank you for the opportunity to address you this morning on these issues.

E.ON U.S., acting through its operating companies -- Louisville Gas and Electric and Kentucky Utilities -- have perhaps a unique perspective on the issue, and my remarks this morning will address primarily, the issue of the free-rider.

We were both a member of the Midwest ISO and are now currently operating under an independent construct with the Southwest Power Pool, providing services as our independent transmission operator and the Tennessee Valley Authority, providing services to us as our reliability coordinator.

As I said, our perspective is unique. I would not want any of the comments that I'm to make this morning, to be viewed in any way as an indictment of criticism of the RTO construct.

Our decision to withdraw from the RTO, was purely a business decision, based not on policy, but on our estimates of relative cost/benefits.

Speaking of those costs, I'd like to spend a minute and address what we have paid, what we do pay, and what we think we will continue to pay under our current operating construct.

In the withdrawal proceeding, the issue was raised that E.ON U.S., may become a free rider on the Midwest ISO system. The allegation was that E.ON U.S. would receive positive externality benefits by virtue of being on the border of the Midwest ISO, without providing financial support for the alleged benefits received.

Some have suggested that border utilities such as E.ON, should be required to compensate the Midwest ISO for these alleged benefits.

E.ON U.S. firmly rejects the notion that border utilities receive any special services for which the Midwest ISO is entitled to recover costs.

E.ON U.S. does not understand how it is receiving a free ride on the Midwest ISO system, as a border utility. To the contrary, if E.ON U.S. or any other non-member wishes to sell or to purchase energy from a Midwest ISO member, each and every transaction is subject to a Midwest ISO charge.

The transmission rates paid for such transactions, in every instance, include recovery of the Midwest ISO's various administrative costs.

Transmission rates are also based on the Midwest ISO's revenue requirements, and provide the Midwest ISO transmission-owning members, a return on their investment. For example, any such non-RTO member, must pay the so-called through-and-out rate to purchase power from the Midwest -- the MISO Day Two market.

The through-and-out rate is set well above the cost of service and has been the subject of much debate. Through these transmission rates, border utilities such as E.ON U.S., pay for all the services provided to them by the

Midwest ISO, to the extent that they transact in the Midwest ISO.

Border utilities that receive transmission services from RTOs, pay for that service through their rates.

To date, RTOs have not identified any specific special services provided to border utilities, beyond those for which transmission customers are already being charged.

Until such services are identified and supported by a Section 205 filing before this Commission and the Commission accepts such rates for filing as being just and reasonable, the threat of additional RTO costs on border utilities, should be removed.

In fact, E.ON U.S. remains concerned that in the absence of specific factual evidence to support RTO assertions, the border utilities are put at risk.

Although E.ON U.S. has no specific examples to provide the Commission at present, the Company is concerned that a permissive atmosphere with respect to this perceived issue, could lead to behavior in the future, that is discriminatory to border utilities.

Notably, even if the Midwest ISO is able to demonstrate that it provides uncompensated, nonreciprocal benefits and services to the border utilities, E.ON U.S. should be exempt from paying any increased fees, to the extent that it does not already -- it has not already covered those fees through the payment of its exit fee.

Recall that E.ON U.S. paid the Midwest ISO an exit fee of almost $34 million, representing the value of past and future costs of Midwest ISO programs that were completed or planned prior to E.ON U.S.'s withdrawal.

Now, some specific operational concerns and commercial issues: As I mentioned earlier, TVA acts as the reliability coordinator for E.ON U.S.. TVA is a signatory to the Joint Reliability Coordination Agreement, along with the Midwest ISO and PJM.

The purpose fo the JRCA is to allow information exchange between and among the parties, and to establish congestion management protocols for common flowgates among the parties.

Under Section 2.3.5 of the JRCA, quote, "Each party will perform this agreement with respect to each control area for which the party serves as transmission provider and with respect to each control area for which it serves as reliability coordinator."

In other words, because the TVA is E.ON U.S.'s reliability coordinator, the E.ON U.S. transmission system is subject to the information and congestion management protocols of the JRCA.

During the withdrawal proceeding, it was suggested that E.ON U.S. should have to compensate the MISO and/or PJM for the commercial value of the information and operational assistance.

However, the JRCA clearly states in Section 4.2, that, quote, "Each party shall bear its own cost for providing the data and information to the other parties as required under this agreement," close quote.

The parties are also required to bear their own costs of compliance with the congestion management protocol, or reciprocal coordination of flowgates under the JRCA, or costs of compliance with the emergency procedures.

Both PJM and the MISO act as a reliability coordinator for entities other than their RTO members. If PJM and MISO propose to charge E.ON U.S. for providing services under the JRCA, then TVA should be allowed the same opportunity to charge PJM and MISO reliability customers for all reciprocal services.

To proceed otherwise and charge only E.ON U.S. for such information and coordinated congestion management provided by the RTOs, would be unduly discriminatory.

Given the reciprocal nature of these services, it is entirely appropriate that PJM and the Midwest ISO, recover these costs from their own reliability clients, just as TVA recovers them through fees charged to E.ON U.S.

Importantly, under the JRCA, the Midwest ISO and PJM submit -- excuse me -- there is an issue that arises also -- and I see I'm running out of time -- with respect to real-time and day-ahead access into the market, and I can address that later.

Let me just conclude by saying that I raise these specific issues, not to complain about the consequences of our business decision to withdraw from MISO, which we still believe to be correct, but, rather, my point is, that if the Commission looks at the alleged positive externalities, it needs to balance those positive externalities against the costs, the burdens, and the obligations that are imposed on those of us who are not a member of an RTO.

The issues I have addressed, are just a few of those currently facing the utilities. We look forward to participating in this conference and with the Commission, to assist as best we can, to resolve these issues in the future. Thank you.

CHAIRMAN KELLIHER: Thank you. I would like to now recognize Larry Thorson, President and CEO of GEN-SYS Energy. Thank you very much.

MR. THORSON: Thank you, Mr. Chairman. It's my pleasure to appear before you today. My name is Larry Thorson, and I'm President and CEO of GEN-SYS Energy. It's a Minnesota marketing and supply cooperative providing energy marketing services to its members.

Prior to my employment at GEN-SYS, I was an employee of General Power Cooperative, holding various positions of planning and operations.

I'm currently the Chairman of the MAPP Regional Transmission Committee, a member of the MAPP Executive Committee, and Board Member of the Midwest Reliability Organization or MRO.

GEN-SYS Energy provides marketing services to its members, including Dairyland Power, which is currently surrounded by the Midwest ISO, so I think I'm very qualified to talk about seams issues.

Dairyland has over 250 transmission interconnections with its neighboring utilities, all of which are members of the Midwest ISO.

Of the 900 megawatts of member load, more than 200 megawatts is located within the Midwest ISO footprint.

GEN-SYS serves as the market participant for this load under the MISO Transmission and Energy Markets Tariff.

My purpose here today is to highlight seams issues related to MAPP and MISO, and to demonstrate the value that border entities provide and to dispel the notion that entities bordering RTOs and ISOs, are not paying their fair share.

The MAPP region has a rich history of IOUs, state/public power agencies, Federal Power Administration, cooperatives, and municipals working together to provide reliable energy services at reasonable cost.

Examples include joint agreements to build and own transmission to avoid duplication.

Transmission was often defined, not by load or control area, but what was least cost to serve the combined load:

The MAPP Regional Transmission Tariff, which is a discount transmission service; loss repayment procedures with energy return, like in-kind; numerous joint ownership of generation; MAPP-reserved sharing pool.

Accordingly, MISO and the non-MISO load for Dairyland, and the load-serving entities that have historically participated in MAPP, as a whole, are heavily integrated with multiple seams between the parties, necessitating a strong working relationship.

We have a contractual relationship with MAPP. We are the viability coordinator. We perform these services out of the Carmel and St. Paul offices, and MISO is the MAPP services scheduled account administrator which will avoid short-term, point to point service MAPP wide at a discount rate to all those, including MISO members.

MAPP and MISO have a seams agreement which MAPP members are participating, along with MISO members and the Midwest Contingency Reserve Sharing Group, or CRSG. MAPP's participation allows MISO members to lower their reserve obligations. We enjoy the total reduction of 1569 megawatts. Excuse me. All the members enjoy the reduction of 1569 megawatts. MISO members saw a reduction of 1203 megawatts, or 77% of that reduction.

So flow gates are often a limiting factor in our ability to secure transmission services to facilitate bilateral transactions into and outside of MISO. At the present time, flow gate coordination from the MAPP system involves 19 MAPP flow gates, 102 Midwest ISO flow gates, 11 PJM flow gates, and seven SPP flow gates.

Loads served by Dairyland and Gen-Sys get all the FERC approved charges to serve longer than the MISO within the MISO footprint. MAPP participants load outside the MISO footprint. Dairyland and Gen-Sys pay for the reserve sharing group. Gen-Sys would be willing to pay for MISO transmission service when and if it becomes available.

The MAPP and MISO seams agreement, while providing for flow reporting between MISO and the non-market MAPP area, and providing enhanced coordination in transmission services has, in my opinion, not created any additional transmission availability at this time.

The MISO liability coordinator has redirected, redispensed our generation within the MAPP during certain emergency conditions, which the MAPP members have accommodated without any compensation.

An example of this related to my company is the Gen-Sys transaction which curtailed due to system constraints.  Through MISO's help, Gen-Sys arranged to a countervailing transaction that produced counterflow that reduced the constraint and allowed that transaction to resume.  However, once that reduction in flow had occurred, MISO redispatched the system, and once again, our transaction was curtailed.

Simply said, there's an equity issue there.  The CRSG MISO members recently voted to incorporate their approved ARC procedure into their contingency reserve obligations.  In my opinion, doing so placed a greater reliance on non-MISO members.  As MISO's area service market evolves, transmission studies may show that MISO has insufficient transmission to deliver reserves to its members within the traditional MAPP region without the use of MAPP or border utility transmission systems.

In going with the comments that were made earlier today, in day one, we dealt with loop flow. We'll always deal with loop flow. Expanding the borders of RTOs and ISOs, in my opinion, does not eliminate loop flow.

The concept of bordering RTOs and ISOs somehow assume a financial obligation because their neighbors chose to join the RTO is wrong on facts and public policy. It ignores the rich history where MAPP came from and existing relationships in the MAPP region. It's contrary to open market theory.

The best means of influencing the seam is for RTOs and ISOs to provide cost-effective services and benefits. It ignores the benefits to RTOs and ISOs that are provided by entities which I have highlighted and ignores the cost and curtailments imposed on non-RTO members by RTOs and ISOs for which is there is no compensation. And perhaps the thing that I feel most strongly about is truly contrary to development of true partnership in which both parties support the endeavors of the others in the pursuit of their business and economic interests, correctly meet RTO participation in voluntary groups that foster the environment in which MAPPs and MISO will continue to work here.

Placing one party in a superior position to that of the other does not and will not foster that relationship. That is necessary to complete those objectives.

Thank you for the opportunity to express my opinions.

CHAIRMAN KELLIHER:  Thank you very much.  Before we turn to questions, first of all, I just want to say that I hope that staff will be actively involved in questions because I think we'll need the assistance of staff to have good questions.

But before we get to questions, I just want to see if anyone on the panel felt the need to react to something that your fellow panelists have said.  Sometimes that helps us a lot to see a little bit of dialogue between or among panelists.

So before we get to questions, I just want to see if anyone has a burning desire to respond to something another panelist has said.

(No response)

CHAIRMAN KELLIHER:  I see no hands.  Either you're a very polite group, or there's not much disagreement among you.  I don't know which to conclude.

Let me ask a few questions of our colleague, Chairman Adams.

First of all, when you talked about internal seams, are you talking about load pockets or internal congestion?

Are you talking about transmission congestion within an RTO, and that's the seam that you're referring to?

MR. ADAMS: I was trying to make a couple of points. One is we don't really have a universal definition of a seam. We don't fear one. And as far as I can tell, our definition of a seam is price divergent, either through a transmission. We typically think of it as a transmission outservice or transmission inservice. As a theme we can all look at, it's tangible and it's real. But that tends not to be the exclusive definition of a seam.

Within New England, which is the context I'm most familiar with, we have transmission seams. We have transmission broken up at two levels, non-PTF transmission and PTF transmission. If you are a generator located on non-PTF and certain utility service territories, you've got to pay outservice within New England to that local utility to reach the New England market.

Within New England, as well, there are seams in the energy market today. And if the forward capacity market gets implemented, there will be potentially seams between the capacity markets. Those are commercial and economic seams.

Our basic view is that these seams, whether they're real, tangible, classic definition of the seams that we used to talk about in the nineties around transmission through an outservice, or whether they're created by a market, are really just a battery on economic relationship and the allocation of cost in order for that economic relationship to function.

And as we talk about it, and as we think about seams, when you change that economic relationship by building transmission, by doing a postage stamp rate or some other mechanism, you invariably change the incentives for the relationship. Before you do that, you need to think really carefully about how you're changing the incentives.

Our view, and it's the main Commission's view now for going on ten years, and my personal view, whenever we change an economic relationship, we got to change the way we make it a part.

It's been fascinating to me, listening to my colleagues, when I was in private practice, I got paid to work really, really hard to make sure my clients got a bigger piece of the pie.

I don't mean to disparage my colleagues on the bench, but that is a lot of how this dialogue typically is shaped.

If we're driving to create bigger markets and more efficient markets and more liquid markets, either within an RTO by eliminating the seams within the RTO, or expanding the boundaries of trade, focusing on making the pie bigger is the way to resolve the issue because the litigation never stops, if you're talking about carving up the pie you've got.

CHAIRMAN KELLIHER: Thank you.

With respect to making the market bigger or having the boundaries encompass a larger area, you participated in the 2001 settlement discussions.

MR. ADAMS: I did.

CHAIRMAN KELLIHER: You actually played a closer role than either me or my colleagues. Are you proposing another round of negotiations?

Are you saying the boundary should be larger?

MR. ADAMS: People that shared that experience with me in 2001, which should be as I suggested that we reinvent that.

(Laughter)

MR. ADAMS: And my wife would shoot me.

I think that the boundaries of RTOs, what's fascinating to me about it is that since 2001, the biggest benefit that I saw from that experience, and the Commission was really much farther ahead of most of the stakeholders in 2001, and I think that that's positive for the Commission.

The RTOs started working together more closely after that point than they ever had, and they started looking beyond their borders than they ever had.

At the time, it was very difficult to trade capacity, for instance, between New York and Nepool, and now you can. Those activities, whether you create one big RTO or not, the activities of trading capacity and making the energy markets more liquid all have the effect of making the market bigger, notwithstanding the governance of the RTO.

That has tended to benefit all consumers. And in my view, when we start talking about seams, that really ought to be what our focus is, which is how do we create the right economic signals for loads and for generators across these boundaries so that we get the most role, the consumers?

And I think it's achievable. I think the RTOs from the past five years have done a really good job of working in many respects behind the scenes to make that happen.

CHAIRMAN KELLIHER: Thank you. I'd like to ask Mr. Ott a few questions.

You identified two major issues you thought we should concentrate on. One is the loop flow issue.

And, Mr. Thorson, I am trying to characterize your position without misstating it. But you seem to suggest, you seem to be less concerned by loop flow, perhaps suggesting that you ultimately can eliminate loop flows.

And I don't know whether you're suggesting you can't minimize them, but you seem to have a disagreement on loop flow. And I'd just like to ask Mr. Ott to respond to your comments. And then, of course, give you the opportunity to respond.

MR. OTT: Again, the key here is PJM and the MISO have taken on what I'll say their responsibility or accepted the responsibility when our market expanded, for instance. We actually calculate every 15 minutes and report to NERC our flow down to zero percent on flow gates. So it's actually we attempt to account for all of the flow that our generation to load dispatch is creating.

In the non-market areas, what's reported to NERC is the control area to control area transactions based on contract path. There are essentially no actions taken based on the procedures if the pond transfer factors are below 5% and the generation to load power flows are not reported in real time. They're reported based on, for instance, an annual flow pattern, which obviously the power system is dynamic.

I see it every day and the flows change wildly. It's just not accounted for. And the point is that while it may have been -- I personally don't believe so, but it may have been okay in the past. The point is it's not reliable and it's not efficient to move large amounts of generation around in the hopes of trying to capture the flow that's occurring on the loop flow through the IDC, the NERC process.

It's very inefficient. Technologically, we could measure these flows. This is not unmanageable. This can be done. We're approving it on a large scale with PJM and MISO.

What we're asking for is for those flows to be captured. I agree it's not proper. If he's providing congestion relief, he should be compensated. But the point is, everybody needs to report their flows accurately so everybody can be compensated appropriately. If you have discontinuities, it's not equitable.

I would certainly agree that you should be compensated for curtailment if you're curtailing to help someone else. But to be honest, we are curtailing a lot more than others are right now, and we're not being, quote, compensated. But it's the right thing to do.

And again, when we expanded our market, we were given the mandate from the Commission to hold others harmless and we took that to the extreme.

Again, I would invite anyone who believes the flows are showing up on their system and they have no recourse because the recourse they have is, of course, to call TLR and get us off.

Come talk to me because I don't believe that is true.

CHAIRMAN KELLIHER: When you're curtailing on behalf of non-members, is it other RTO members or non-RTO members?

MR. OTT: How they curtail you?

CHAIRMAN KELLIHER: You said you're curtailing frequently on behalf of non-members. Is it on behalf of the sister RTO or its members?

MR. OTT: If MISO has an issue, meaning we have a flow gate where our market flow is affecting it, we do that through the JOA. And there's actually compensation that gets done.

If there's an external entity who has a flow gate issue and our market flow is affecting that, it's entered into the NERC IDC and we curtail based on redispatch instead of cutting transactions.

We do that, again, as part of the NERC process. We cut our share, if you will, so we're assigned a certain amount of relief.

CHAIRMAN KELLIHER: What if you curtail on behalf of the New York ISO? Is there compensation?

MR. OTT: At this point, there is no such agreement between PJM and the New York ISO. We reached out to the New York ISO. I assume you'll hear from them later. They are interested in talking to us about that type of agreement.

CHAIRMAN KELLIHER: I didn't follow one of the comments you said about flow data. Is it pricing data that you think you need, or physical flow data?

MR. OTT: It's physical flow data. A perfect example, if somebody wants to sell into PJM under today's approach, they could have an entity down in Louisiana, for instance, or anywhere saying, "Okay. I'm going to sell into PJM." PJM has a couple of border prices. If I create a contract path schedule through the land, if you will, and sell into the highest price.

Okay. That will be the best thing for me to do. And since I can't see any of that contract pass off that's occurring until it gets to my border, the entity can come. And that's one of the phenomena we saw where the flow actually originates, for instance, just an example, in Louisiana, but they tell us it's coming into our border in South Carolina or North Carolina.

So I'm paying them a price as if they were coming in an area where I would like generation to come in because it reduces congestion. But the fact is, if you trace it all back through, then I have the flow actually came from a harmful spot.

If I can't accurately calculate their flow data, this has to be on a large scale, then I shouldn't be paying them the locational spot price. My members are paid locational spot price because they give me -- all of their flows are revealed.

CHAIRMAN KELLIHER: Hypothetically, you would need flow data from how many transmission operators from Louisiana through North Carolina?

MR. OTT: You essentially need the flow data on an accurate basis. Again, the contract path concept, okay, is -- needs there's a better way. And I think this is not saying there have to be a market. This could work for pockets of non-markets. The point is there is a lot of flow out there on everybody's system that's not accounted for.

CHAIRMAN KELLIHER: You need flow data beyond the contract path from Louisiana to North Carolina.

MR. OTT: You also need the generation to load power flows that are being generated in real time.

CHAIRMAN KELLIHER: Okay. Mr. Thorson, do you have any comments?

MR. THORSON: Louisiana to North Carolina.

MR. OTT: You also need the generation to load power flows that are being generated in real time.

CHAIRMAN KELLIHER: Okay. Mr. Thorson, do you have any comments?

MR. THORSON: Yes. I think you'll find that Mr. Ott and I are on the same page. My point was we've always had loop flow. We're always going to have loop flow. It's not going to go away. I think Andrew's point is more give me information so I can help manage that flow. And I don't disagree with that at all.

I think, really, for me personally, having been involved at one point in time on the operation side, at one point in time on the transmission planning side, the culprit on all these seams issues is transmission. We're trying to do things today that the transmission system wasn't built and designed to do. And with that, the seams issues are many.

Basically they create flow gates. Lack of transmission creates numerous flow gates, which all have to be managed for a good reason, for security. That necessitates close coordination amongst participants. It creates price disparity. It also can eliminate the ability of third parties to participate in reserve hearing groups because there's insufficient transmission to deliver and may cause a certain group to carry a higher level of reserves than another group might.

Also, generation, running out of mechanized merit. And last, but not least, cost just to participate.

CHAIRMAN KELLIHER: Thank you. Colleagues, Suedeen, Kelly, Andy, on a scale of one to ten, how big is the loop flow issue? First in terms of reliability and system management, to the extent they are the same? And second, in terms of economics, meaning direct economic cost to you or perhaps indirect cost to the market?

MR. OTT: Again, to me, since I don't operate in the market, the costs aren't necessarily to me. But obviously, the cost to my members is really what is my concern because my job is to ensure that my members get what they need.

I think the answer is, again, the issue at Chambersburg -- I'll see if I can raise that here. We had estimated 20 to 30% of their reduction in their annual entitlement of transmission rates was caused by our need to recognize that we had increased loop flow. We saw, again, a thousand megawatt increase in loop flow over a span of months. That cost to them, essentially, was, again, a third of the transmission rights they didn't get for the year, which was a very substantial cost.

We were short in congestion revenues that year. I believe it's on the order of $150,000,000. Again, if 30% of that was loop flow, it gets a fairly significant dollar amount. Again, that's only the loop flow change.

Then I said, okay, and I looked at the change in loop flow. What about all that background loop flow that we've all said is there and continues to be there?

If you look at that also, it amounts to a significant amount of dollars. Again, I agree you're not going to make loop flow go away. The point is that, at this point, it's uncontrollable. I have no recourse for the flows that are generated out of my system that are below 5%.

Let's not have if somebody creates a transaction and it has a 5% effect on my system and I ask for it to be curtailed, the incentive I have is to create a set of transactions that are just below 5% from control area to control area, and I can create several transactions, okay, and get around it. So the loop flow comes back.

It's just no a reliable way to manage the real time flows. Everybody realizes that the process is cumbersome. It's not the most reliable way to run the system. We know there's a better way and the technology exists to do it.

COMMISSIONER KELLY: It's not a reliability problem because you're managing it, but what's the cost of managing it the way you have to manage it?

MR. OTT: I don't know that we've gone to the point of quantifying all loop flow. I think the incremental cost of our existing -- I'll call it the increase in loop flow. Probably the best I can give you is 30 to $50,000,000 in the previous year. But the costs are probably higher than that because we've tended to be in the mode of living with it.

And I think the point is that as we look further in this, I get all this data that I was able to put it together. The amounts are quite large.

COMMISSIONER KELLY: Taking a page from Kurt's book, if we were to look at this as an opportunity, a potential opportunity to enlarge the pie, is there a way that engaging non-RTO members on better managing loop flow would make life better for them, or is this just going to make life more difficult and more costly for them?

MR. OTT: I think you will hear from non-RTO members that they've been subject to loop. There are some control areas or if you want some of the control areas sending power in to me, 40% of the sales into PJM flows through the adjacent system, and neither one of them are in PJM.

But the point is there are the two of them and they impact each other, whether they sell to me or sell to somebody else.

My guess would be if we all -- obviously if you account for all the flows, somebody is going to lose, somebody is going to win, because today, there's an inequity.

The point is, if you get more accurate, you actually will account for the flows that are occurring. I think it's a better answer.

COMMISSIONER KELLY: Steve, I understand that PJM has a bigger loop flow issue than MISO, but is yours significant?

MR. KOZEY: It is significant. We didn't get the same data Andy did. But the kind of thing that in our first month of market startup got some of the biggest flack, this Commission got to remind us of how to charge better regarding -- in our market, it's called revenue sufficiency guarantees.

When you choose to tell a generator to run to get on, to start up in real time or short lead time, what wasn't on on the day before you create cost, why did it take us so long to get that under control?

Loop flow assumptions and models based on people outside our market, from these NERC standard or regional standard develop once a year kind of on average. But without this real time dynamic stuff, you set up your day ahead market based on a set of assumptions that had been good enough in the industry.

We run our STR process with a lot of those same loop flow assumptions, and then real time is substantially different. It causes this increase in what the economists say is out of merit.

I hate that term, but necessarily committed in merit at the time, peaking resources. But that's a cost that's then spread. But also the disparity then can frustrate long-term transmission right holders, who are right up to relying on this FTR revenue as their congestion hedge.

Sometimes when Mr. Stuart or Mr. Filley, who are transmission-owning members and load-serving entities in our area come to you and say, "I need better congestion hedge, this is where the marginal improvement in that to get things up to where it can perform is.

COMMISSIONER KELLY: Just asking a final cost benefit analysis problem, are the costs involved in attempting to achieve a better solution to the loop flow issues substantial, and would they justify the benefits that could be achieved by managing it better?

MR. KOZEY: I'll offer this without having had the engineer's support. I'd say it's a lot less than many of the other things that go on in improved coordination because you're talking about getting systems to utilize all of the extent communication protocols that exist.

You don't have to build a new wide-area network. You don't have to build a new Internet. You've got to get information that you already have as a control area experiencing real time push up. So as to who benefits or society would benefit. There would be some cost shift.

But Chairman Adams talked about solutions are better when they increase supply. If you had a better management of even the TLR curtailment in the non-market areas, that's so inefficient that I bet you we could get back inefficiencies there at cost collectively that control areas experienced to push this information up.

MR. ADAMS: What I think is interesting about this conversation is that it really doesn't have a whole lot to do with whether or not there's an RTO in the mix. We really have our smaller utilities in New Brunswick which is not an RTO. It's a control area. We have loop flow issues there, and it has more to do with having an interconnection than having joint planning processes in the discussion as we have it in this contact with this proceeding of neighboring control areas to an RTO.

It's an important that where some of these things just have to do with neighbors as opposed to there being an RTO or not in the mix.

COMMISSIONER KELLY: Kurt, I heard your testimony. I do recall that there were a number of years in which MISO in New England, ISO, I guess at the time, trying to put their markets together, pursued putting their markets together, and it didn't come to fruition.

When you talk about enlarging the market, is that what you're thinking about? If not, are there other ways to do it in New England, and do you think conversations might be more fruitful now?

MR. ADAMS: It's interesting. My basic view is that the commercial operation and the commercial opportunity ought to drive the governance structure, not the other way around.

What did come out of those conversations, as an outside observer to those discussions, it was never really the will from New York and ISO New England to come together. They're never really wrong, and there are a lot of reasons why, some of which has to do with political differences between New York and New England, institutional issues.

But what did come out of that is, in the late 1990s, you couldn't trade capacity. It was a really big deal. Today, there is an ability to trade capacity. There's much more communication between the two and there's much more commercial opportunity in governance structure.

One single RTO to neighboring RTOs, RTO with a non-RTO next door, in many respects, is a less interesting question for all of us. The platform their commercial operation is allowed to exist, notwithstanding the governance structure.

COMMISSIONER KELLY: When you're talking about enlarging the markets, you're really talking about elimination or reduction of the seams.

MR. ADAMS:  I'm talking about eliminating uneconomic seams.  There are seams that exist that just reflect the economics of a situation.  Locational marginal pricing is one.  Through an outservice under certain circumstances, though we tend not to like a few.  Sometimes you get service is an important purpose because that's how you get important infrastructure built and paid for.

But the market activity ought to really try what the governance structure is.  Whether or not there is an RTO with a neighbor, in my view, is sort of an interesting fact, and a lot of the discussions ought not be a driving consideration.

COMMISSIONER KELLY:  Steve, one of the issues giving rise to this conference was the exit of LG&E, not that LG&E caused a problem, but it raised the reality that these are voluntary organizations, and transmission owners may exit.

Is that a concern to MISO, or how big of a concern is that to MISO?  And do you have any data that shows costs value of this kind of situation?

Obviously, there's value to having the MISO there and there are costs.  There's obviously value and costs to entities that are on the borders dealing with MISO.

Do you have data about the role of costs and values?

MR. KOZEY: Yes, but not sufficient to start the record for the Commission. Some of the difficulty is in traditionally, when people talk about the value of a proposition for a larger market, we've tended to look at studies that have been forward looking that use production cost modeling studies, widely used in industry to justify mergers, to look ahead and decide whether you're going to build a coal plant, a gas plant.

In looking at that, we end up sometimes confusing that as the sole quantifiable benefit on these operations. The reliability stuff we're talking about is really hard to quantify.

The central planning benefit is very hard to quantify. But, yes, now in terms of what kinds of -- I'm the Secretary Chairman. Kelliher read out all these titles I've got at the company. I'm in charge of membership.

So if someone wants to send a withdrawal notice to the company, the letter is addressed to me. And we have a lag. A notice can come in by you to be effective no earlier than December 31st the year following.

The notice is not a guarantee that a withdrawal proceeding is going to start. The notice creates an option for the transmission owner. Every transmission owner can be expected to act with its view as to its own commercial judgment. And sometimes what can happen is our structure or the Commission's rules create an uneven movement against the status quo. We do something new or the Commission does something new. Some people benefit more than others. Some managements may believe that they're subject to a cost.

I mentioned the non-jurisdictional utilities, and the Commission C structure. It may seem a very small notion to you if out of our 29 or $30,000,000 that we collect and give back to you, let's say $3,000,000 of that comes from municipal and cooperative transmission owners.

But it's a big deal to them. They sit around and do their calculation of well, how much benefit am I getting from the Midwest ISO? I already know that I pay that organization and I pay something extra for FERC. They count those things.

So I do support volunteerism. We don't have many opposite views in our economy, and certainly in this Commission. It assures that management tries to stay attuned to the needs, desires and circumstances of members. And it would blunt our attention to their needs if it were not voluntary.

But the benefit showing on us is not just a general or societal benefit. We have to make convincing arguments to individual transmission owners about how they're going to do today, tomorrow and in the future in our market.

COMMISSIONER KELLY: Do you have the data to make those arguments?

MR. KOZEY: Often. Sometimes it's confidential to an individual market participant, and it has to be sort of we're not your consultants, but we think you're leaving money on the table. If you will open up your thinking as to how to use the market, there's a lot there for you to succeed. Be successful in some of that.

The reliability part I think it growing where the awareness of the companies is more immediate. Consumers energy, CMS, I believe copied you a letter in the late summer that said they didn't believe they could have made it through the seller without the five-minute redispatch option that the RTO provides when they lost substantial nuclear generating assets in peak periods of time.

That sort of stuff happens routinely, and it's not news anymore. We had a member company last Saturday, non-peak time, lost 1700 megawatts of generation, and their load was 1200 megawatts. They didn't even have to declare reserve sharing in that in five minutes, the results of that forced outage were that they were redispatched power at about $35 a megawatt hour.

In the old non-MISO world, if you asked that company what it would have had to have paid to replace that

1700 megawatts in the market, I assure you they would have paid more than $35 a megawatt hour.

How to convince people that they know that stuff happening only to attach a dollar value, because it's an avoided cost versus a real cost, that's still a big challenge for us.

COMMISSIONER KELLY: That's also a new development, and I think we should turn to our colleagues.

Can I ask one last question?

CHAIRMAN KELLIHER: With a very short answer.

(Laughter.)

COMMISSIONER KELLY: Has the adoption of mandatory reliability standards increased or decreased the value of membership in an RTO? Or do you not know the answer yet?

MR. KOZEY: We know that some companies wanted us to assume our duties.

CHAIRMAN KELLIHER: She should have said increased or decreased and gotten away with that.

(Laughter.)

MR. KOZEY: Increased.

COMMISSIONER KELLY: Andy?

MR. OTT: I think it increased the value of being an RTO.

COMMISSIONER KELLY: Thanks.

CHAIRMAN KELLIHER: Thank you very much. Commissioner Spitzer.

COMMISSIONER SPITZER: Thank you. Mr. Chairman, Mr. Beer, welcome. Mr. Kelly teed up the topic of the voluntary nature of RTOs, which means lawfully, and these controlling our withdraw.

The withdrawal preceded my tenure, and I wanted to explore that a little bit and maybe drill down and see if we can come up with some observations, particularly with regard to the temporal nature of the decision.

I'm assuming that there was some consideration of this matter by the Public Service Commission of Kentucky. Can you describe that?

MR. BEER: Commissioner, that's true. The Public Service Commission of Kentucky initiated an investigation on its own into the costs and benefits of LG&E and KU continuing its participation in the Midwest ISO. We went through that process with the KPSC and performed a number of cost benefit analyses.

That proceeding spanned almost two years, I think it was, where we went through a number of hearings and several rounds of written discovery and several days of hearing. It finally did conclude with an order that found that the benefits did not exceed the costs, at least as it pertained to us, and directed us to take action accordingly.

COMMISSIONER SPITZER: Was that proceeding -- did it result in a determination? And, again, exploring the temporal.

Mr. Adams talked about making the pie bigger and alluded to certain long-term benefits. How long term was the thinking as to the fact that it was ultimately deemed to be in the ratepayers'interest that you withdraw?

MR. BEER: If you're asking me about --

COMMISSIONER SPITZER: I'm not asking you to be judgmental about that recommendation, because your record, presumably, that suggested at a certain point in time it was a negative.

Did that incorporate potential future benefits?

MR. BEER: We looked at what we expected to happen, how the Midwest ISO was growing, evolving and developing in the day two market and subsequent other initiatives. It was our perspective then that the benefits did not outweigh the costs.

If we were asked to make a similar decision today, it would be our position that the decision to withdraw remains beneficial for our customers.

COMMISSIONER SPITZER: Does that view change if there were some certainty with regard to federal carbon legislation, for example, that might impact the cost of generations in the state of Kentucky -- Commonwealth of Kentucky -- excuse me.

MR. BEER: It would depend entirely on what the nature of that carbon legislation provided. Presumably, it would increase the cost for all fossil generation. So I would expect, if there is an increase in cost due to carbon, I would expect that the relative disparity between costs and benefits to be roughly equivalent as we would move through the early periods of the carbon constraint period.

COMMISSIONER SPITZER: Kentucky was an exporter as a jurisdiction. I would assume you are correct. So that played some role in this determination.

MR. BEER: The role that was played primarily was the fact that our costs of generation were among the lowest in the country. As a result of that, it was exposing our customers to the potential to pay significant higher costs for generation than otherwise would be the case were we dispatching generation the other way.

COMMISSIONER SPITZER: There's something by virtue of exports. It would create upward pressure on Kentucky consumers.

MR. BEER: It would be the operation of the day two market, the disconnection of generation and native load where the generation would bid into the market and load would bid into the market. And the function of LMPs where we would be in the position of native load, having to buy generation out of the day two market at a price higher than what it otherwise would have paid had it remained connected as it were.

That's not an artful term, but not in a day two market.

COMMISSIONER SPITZER: Systemwide, RTOwide, Kentucky's participation would have yield benefit consistent?

MR. BEER: Yes. If there are higher costs and lower cost utilities, and the purpose is to try to average those costs, then presumably the lower cost to generation, wherever situated, would provide net benefits at least to those who have higher net cost generation.

COMMISSIONER SPITZER: I don't want to be argumentative, but if we follow that reasoning to its logical conclusion, no net exports date would ever be an incentive to join an RTO.

MR. BEER: I think that's an accurate statement.

COMMISSIONER SPITZER: Given that there's a long, articulated federal policy on this matter and what Chairman Adams said intuitively I believe to be correct, which is the larger the economic unit, the more efficiency.

How do we resolve this dilemma? Again, this is on a going forward basis. I'm not trying to relitigate your particular matter. I'm just trying to see what observations we can make, what things we can learn from that decision-making process.

MR. BEER: It's an interesting question, obviously, and it's not one that I am sure I can thoughtfully answer today. But the fact that there will always be higher cost and lower cost to date, higher cost and lower cost control areas presents a problem that is admittedly very difficult.

There may well be ways of creating market mechanisms that appropriately allocate costs, but also appropriately recognize benefits. To do anything other is to penalize the customers of those low-cost utilities who have, for whatever reason, put their customers in a position of benefiting from that historical position.

COMMISSIONER SPITZER: That leads into Chairman Adams' point. As always, I carefully listened to your comment. You described the disincentives with regard to construction transmission that would net benefit the region.

Let me give you an analogy here. In the early 1950s, the federal government decided that we needed an interstate highway system. There was some fight back initially in the early fifties, and I believe there was a Senator from Rhode Island who was complaining about Route 66 in the west. Yet the Sinatra song was evolved into a new highway system, not just Interstate 40, but throughout the country so that although there was resistance initially, and they were very definitive and observable and measurable winners and losers with the construction of the highway system, people in Philadelphia could get fresh lobster that evening. People in Arizona have this oxymoron, fresh frozen by the interstate highway system.

There is no question now that we've expanded the pie. You explained the dilemma of confronting the state of Maine with regard to potential renewable resources and the fact that you people are penalized in two ways with construction transmission.

One, the socialized costs are absorbed by your rate payers. Secondly, you got this, again, upward pressure based on the exports. So you've got these conflicting principles. Yet, if our lodestar belief is articulating the federal view, the bigger the market, the better.

I associate with your statement, and secondly, take a long-term view of the situation. I think that's what is typically the best view and the one with the longest horizon.

How, from your perspective, do you resolve that dilemma?

MR. ADAMS: I'm still thinking of the Sinatra song.

(Laughter)

MR. ADAMS: And wait for Don Downs to come out with a song like the southwest group that could save one upgrade to get us out of romantic. How about that investment.

(Laughter)

MR. ADAMS: The interstate highway example, I don't want to be pedantic, but I just have to respond.

The interstate highway is a great example, and that is a great example that actually proves my point. The reason it does, I'm at the tail end of a family vacation, and one of the things that we did is we tortured our three kids and we drove them to Washington, D.C., our nation's capital. And there are a lot of toll booths between Maine and Washington, D.C.

Folks talked about, in New England at least, our transmission system. We talked about a postage stamp rate on our PTF transmission system. That means more toll booths. It means our rates are not distance sensitive.

It's majorally different from the interstate highway system when only the toll booths -- if you're going to ship lobsters from Maine to Philadelphia, you've got to put them on a truck. You've got to buy the fuel. I'd be willing to bet that when I buy lobsters from my cousin, they're a lot cheaper than what you pay in Philadelphia.

The reason is not only -- trust me, my cousin is getting it for free.

You've got to move those lobsters. You've got to pay those tolls. You've got to pay for all that fuel.

That's how economics are supposed to work in the transmission system as well. If you have a postage stamp rate, you got to completely socialize to transmission system. You change the incentive on the cost of generation.

What you do is, instead of valuing the delivered electron properly, the load pocket has the incentive not to site generation, to site generation remotely and ship it in. If you socialize that cost, the issue of socialization is an interesting one because what it does is changes economic incentives.

The basic question about larger markets, though, I think is materially different. You can have these things in the interstate highway system. They're called toll booths. You can have these things that pay for some of the cost of the infrastructure for which we all benefit. If you didn't have the cost allocation that way, you probably wouldn't go back system.

That is what I think about when we are talking about building larger markets. You have to have the economics right because the economics drives the right incentives.

I'll give you one example that I've shared with you before. Maine is a net exporter. We've been one for the better part of 30 years. And I want to touch briefly on why Maine and Kentucky are a little bit different.

Maine has 1000 megawatts of generation in the pipeline. New Brunswick, Newfoundland, Labrador, if you listen to what their governments are saying and you take it for what it says, somewhere between two and 5000 megawatts of new generation.

Mostly the types of generation that ISO New England says New England needs. Moving that generation into the market cost money. You got to create the right incentives to build the transmission and build the generation and deliver it. You're probably better off if you don't create the incentive to offset generation that's in the load pocket that will be less expensive.

That's the basic dialogue that I believe we ought to be having around large markets. How do you create the right incentives for resources?

Why Maine and Kentucky are very different, you know, Kentucky has not restructured. Kentucky has rate-based regulation. We don't. Maine's focus on making the pie bigger is driven by that one fact.

We sold our hydros. We sold our power plants. What we have to do as a small state is attract investment capital. So even though we're a low-cost state, that 1000 megawatts is being built by private independent companies that are investing in our state, and they're investing in it to sell south.

Our state needs not to be hurt by that investment, but at the same time, it would be foolhardy for us to create a massive seam between Maine and the rest of New England to chill that investment because our consumers will benefit by it if the economics are right.

COMMISSIONER SPITZER: I understand it's different with regard to Maine's lifeline being the wholesale market now. That's a distinction with a vertically integrated rate-based assets.

Notwithstanding the structural differences, there are certain economic principles that are common, which is you cannot reasonably expect a jurisdiction to support transmission where there is a net -- where that jurisdiction is not being compensated to do so.

MR. ADAMS: That's right. I think you hit the nail on the head. What's the timeframe? I believe that long-term thinking is what's required about these things.

I was at a conference yesterday that Commissioner Wellinghoff spoke at. Somebody raised their hand and said, "Oh, my God. That will never happen. It will take two years."

This is not in the business if you're not into delayed gratification.

(Laughter.)

MR. ADAMS: This is the five, ten, 15-year time horizon business. That's what I believe commissions and utilities really need to be doing, is thinking long term about the decisions they make and the plans that we have that we're working on in Maine, our 10 to 15-year plans.

But over that ten to 15 years, it's really important to consumers that are hosting these assets, hosting the transmission, building the power plants nobody else wants to site, are not harmed by the process.

COMMISSIONER SPITZER: The purpose of my questions with regard to Mr. Beer were -- and I invite any of the panelists to respond to this final point -- having been an elected official, your constituents are interested in their matters. In the case of electric rates, what they're paying in their monthly bill today.

Nevertheless, you've got, even before the mandate for reliability, state commissions stay up at night worrying about how to keep the lights on ten and 15 years from now with regard to generation and transmission. So there is a powerful force in terms of long term planning again, even before mandatory reliability standards.

I think the irresistible conclusion that large markets, again whether it's one RTO or trade among control areas, is in the long-term interest of all the constituents.

So how do we achieve that, given that you may have a potential, given the voluntary nature of the RTOs for an entity to have a dictate come down from a state today where we're under water. Therefore, so what would be suggestions for FERC to ameliorate this?

MR. OTT: One issue. Back to the exporter idea, where the exporter is selling in to the market. Obviously, contractually, the load can be protected. The state can deal with that. But in the absence of that, the fact is that low-cost area does have excess power and wants to sell it.

Again, if this were back to the free rider issue, if the best decision for them then is take your stuff out and just sell off when you want, the inequity though that's created, I think you can do something about says that they shouldn't then just be allowed to sell in when they want because they didn't do anything to make sure that that ready market, if you will.

In other words, the concept of saying I can sell bilaterally versus I can sell to an hourly or whatever robust spot market. I mean there's a big difference between them.

Then I think again, I realize it's hard to quantify all of that, but I think that's the real issue is to say, as Commissioner Adams has said, make sure the toll booth is there.

In the issue of time, I won't go further, but I think that's the real issue.

COMMISSIONER SPITZER: I would point out Mrs. Spitzer, from Arizona born and raised, was horrified by these toll booths.

(Laughter.)

COMMISSIONER SPITZER: She thinks freeways are free. She wouldn't put the quarter in.

CHAIRMAN KELLIHER: We call them throughways here in the east.

COMMISSIONER SPITZER: Steve, did you have any views on this?

MR. KOZEY: Yes, Commissioner, but we stay addressed to it, 890, if I've got my numerical sequence right about regional planning and what regions are important. Do these regions help one another? That we keep the conversation up around that to see if that's where we can go to address duration of planning cycles.

What do regions owe one another when they do this, and how to deal with urging a common standard towards proactive investment that can be a no-regrets investment no matter what climate change legislation or renewable mandates come up that we're not hooked into one future?

MR. ADAMS: I can just briefly answer the question, Commissioner. What should we do?

I am from a resource state, and we need to export to make a living. We've taken it upon ourselves at the Maine Commission to answer your question, and we're in the middle of formulating that. And the one we're thinking about is that if we had a transmission cost allocation regime and a generation pricing delivery regime within an organized market with most of your restructured states, it's incumbent upon the resource states to develop a regime that creates incentives for us to benefit higher cost states.

We're in the middle of developing that process and developing exactly what we have in mind. And we have some pretty positive thoughts about what that would work like, and we'd like to share them.

But I believe that resource states have the obligation to serve high-cost states, and there's an opportunity for resource states to serve high-cost states. And simply taking the ball and going home is not an option for a small state like mine that has restructured.

So I take your question to be a serious one. We're working on developing a really serious answer to it. I think it's probably the single most important question in this whole dialogue of what went on. Our participation in an RTO for a low-cost state makes sense. I hope we can provide you some more details in the next few months.

CHAIRMAN KELLIHER: Right. Thank you. I'd like to recognize Commissioner Moeller.

COMMISSIONER MOELLER: Thank you, Mr. Chairman.

I guess I'd like to focus on the suggestions, Mr. Ott, that you gave us regarding data and how we can drill down a little bit better.

I was reminded yesterday by one of the visitors that the laws of physics tends to trump just about any other set of laws that are out there. And your example of the contract path flows are basically fictional was an excellent one.

I'd ask you, it wasn't just theoretical. That was a very real example, I presume, you gave us.

MR. OTT: Yes. There are situations, if you're talking about my written example, the percentages in that written example are not my wildest dream that this is a very high -- this was a fairly modest assertion on my part that certain flows can occur. As I alluded, there are control areas out there where 40% of their contract path flow shows up where it's not supposed to.

Yes. If that's your question, the percentages can get quite astounding, especially if you're given the volume of megawatts moving.

COMMISSIONER MOELLER: To get to your solution, and I hope you'll maybe elaborate more in writing, in addition to what you gave us, we should be requiring better real time data flow disclosure on the seams, and should the IDC power flow model then be revised by NERC to go down to zero percent is part of the burden on the model need to be, I guess, revised once the range of suggested fixes.

MR. OTT: Again, today, obviously PJM, as the control area for very large areas is probably in the best position to calculate the flows we create. That's exactly what we do. We calculate the flows we create and ship them to the NERC.

Each control area that's in operation today, even though they report their generation to load power flows on whether it be an annual basis or some very ungranular basis, they have to have their flows calculated.

I assume they're operating. They've got to have some idea of how the power flows are affecting not only their own lines, but their neighbor's lines.

I think the point is, as PJM and MISO have done, we've worked with quantifying, getting the accurate calculation within ourselves, and showing those flows that we create to the world.

The question then becomes how do you put them all together?

I can't tell you that I have the design in my head, but I can tell you that, again, technology exists. The data exists. It's a matter of getting it all together and coordinating it.

The first issue I have is the incentive for people to step up and say, "I'm going to do this." It took me, again, five months just to get the data, let alone to agreeing that we needed to do something.

So all of my neighbors I would urge to say, you know, we all collectively have to solve this problem. I realize in the short term there will be winners and losers. Long term, though, I think we'll all be better off. And I realize I'm sitting in the position to say I've already done it all. I've already done it. I've quantified my flows. I'm already doing what I think is right.

But let me just get back to, I think, what I'm asking is for the stuff that's already there to be opened up and made transparent.

As far as how do you actually coordinate it, it could be done through a series of agreements, as opposed to necessarily -- the one thing though is this issue of the 5% cutoff that was approved as a NERC standard. That needs to be dealt with. That, quote, 5% cutoff again, if you have thousands of megawatts flowing, it's not good enough.

COMMISSIONER MOELLER: So that burden is on NERC related to the ITC power flow model. Mr. Kormos will be talking about that this afternoon. We're at zero percent now. We're talking about going up to three because we're taking up too much of the burden on ourselves.

One other way is for that to move down. Obviously, that would be disrupted through the regional transaction which say, okay, just changing the IDC alone isn't the answer. PJM and myself have done majority agreements where there is some coordination, okay, that says, okay, the fact that you put flow on somebody else.

If my answer is just curtailing, then I shut down all trade. The point is, okay, account for it and maybe there's compensation involved or whatever. But I think just saying you're going to change the IDC and have more curtailments, you understand, it's a deeper problem.

As I said at the end of my example, I think it means we have a new way, which essentially is more like the real-time coordination issue rather than just a simple change to the IDC. So I'm not giving you a simple solution here.

COMMISSIONER MOELLER: Your verbal example was a good one in that it skews the market. It is sending the wrong market signals to wherever the LMP price is being paid. Then your written testimony points out this has reliability impacts.

As we go into a new era of more of a focus on mandatory reliability with consequences related to it, I think it's a very relevant topic.

MR. OTT: I have done analyses in the past where if you look at what it used to take to control many, many years ago, I have very old data in this because we haven't done it in detail. It took 30 to 40 minutes to control a line using that sort of less granular process.

Within the RTOs today, with a real time five-minute dispatch, I control a problem in three to five minutes. It's ten times faster and that's a reliability -- huge reliability gain. So I think those issues are going to need to be discussed.

COMMISSIONER MOELLER: Steve, any comments on that topic?

MR. KOZEY: We are in agreement with PJM. We think it works and it can work. These agreements we have with everybody else have been followed here, as well. So if you have a neighbor who says it's not working out perfectly and you need a voluntary agreement, as cooperative as we are, we'll cooperate better and more effectively and against the prospect of resolution by outsiders, if we can.

COMMISSIONER MOELLER: I guess the issue gets changed a little bit when there are internal flows. But, Larry, do you have any thoughts on the granularity of flows as essentially a customer being able to provide that to MISO or another entity?

MR. THORSON: Yes. I appreciate the opportunity.

What I would like to underscore here in terms of the discussion that's taken place this morning is, to refresh your memory, that MISO is the reliability coordinator for MAPP. So to a large degree, it has a fair amount of granularity already relative to the MAPP system. To the degree that they would like more, I don't see a difficulty in providing that.

The point I'd want to make there and the points I try to make in my presentation is that I want this to be pursued as a partnership. I want this to be pursued that we recognize that there's some benefits to be achieved and the parties recognize there should be mutual benefits.

So, to a degree, we will be negotiating the seams agreement I've identified. As the RTC chair, a number of issues that I intend to bring forward in that relationship that don't exist today.

Again, I view this as a package, and this will be a win-win situation.

With respect to granularity, it will and always will continue to be an issue. I can cite an example close to home.

Again, Dairyland Cooperative area surrounded by

MISO, there's an area adjacent to the Dairyland control area that's often beneficial to the system. But because of the lack of granularity, if I was to make a transmission service request, it's going to hit probably half a dozen flow gates all negatively as far as the calculation is concerned.

On a less granular basis, everybody that's from the region knows that's probably one of the best things you can do to alleviate concerns is fire up that peak fire generation and it will solve a whole host of problems.

But because of a lack of granularity, that loss, you're going to get into control area issues, and that's been lost.

COMMISSIONER MOELLER: Thank you. Kurt, thanks for the visit yesterday. I know you've given a lot of thought to this in general, even though it may be a lot of specifics.

But do you have any observations?

MR. ADAMS: I'm going to actually pass on answering the question. Most of it, as general concepts, are beyond what I'm really thinking about specifically right now.

COMMISSIONER MOELLER: I think this is an area we can pursue and potentially solve some of the problems here if we can break down. As people have ideas to better solve this problem, I hope they'll bring them forward.

Thank you.

CHAIRMAN KELLIHER: Thank you. I'd like to thank the panel very much for helping us today, particularly our colleague, Chairman Adams. And we have run really through our break. So I think we'll just call up the second panel.

Thank you, gentlemen.

(Recess)

CHAIRMAN KELLIHER: I'm going to resume. I ask the second panel to come forward and let's close the doors.

I'd like to recognize Ron Mucci, the Manager of Regulatory Affairs for Williams Power Company. Welcome.

MR. MUCCI: Good morning. My name is Ron Mucci. I'm speaking on behalf of the Electric Power Supply Association, EPSA for short, which represents competitive power suppliers, who account for more than a third of the nation's installed generating capacity.

I'd like to begin by thanking the Chairman and the Commissioners for the opportunity to provide comments on the seams between ISO RTOs and the non-ISO RTO utilities, with a particular focus on the market and commercial issues.

While currently not intending to mandate RTO membership, the Commission and the LG&E recognize the potential ability for non-ISO utilities to use and/or benefit from the Midwest ISO's regional market, while avoiding some or all of the costs attributable to RTO membership, which, in our opinion, could weaken the liability of the RTOs and degrade the benefits of competitive markets.

To frame the market dislocations created by such a jagged seam, I'll focus on the functional aspects of the RTO and ISOs and the benefits they bring to the competitive markets, that will be contrasted with the non-ISO markets and address the issues raised at the seam, including the market distortions, inefficiencies and inequities created and borne by market participants.

I will say while Order 890, once fully implemented, may address some of these concerns, we urge the Commission to address the problems associated with border utilities, including those who were former members of RTOs, by first addressing the free rider problems posed by utilities who are not members of RTOs and ISOs, but sit on the seam and take advantage of the many attributes of the regionally-organized market without paying a compensatory share of the cost.

Second, take into consideration the implications to the broader market when they're vertically integrated to seek to withdraw from an RTO or ISO, which are two-fold.

The impact on the remaining members of the RTO and the construct of the non-RTO market and its ability to further the goals of open, transparent, non-discriminatory and competitive markets.

Finally, we believe the Commission should avoid degrading the existing organized markets and ensure that non-RTO markets are compatible and well functioning.

With that, we believe the integrity of the organized markets administered by the RTOs and ISOs should be maintained because they promote efficient, reliable, competitive markets to provide the price and transparency, as evidenced by locational marginal prices or LMPs which provide both day ahead and real time market sequels for energy and ancillary services.

They enhance price convergence at the RTO to RTO seams as exist in the example between MISO and PJM, where protocols have been implemented to their joint and common market efforts.

They provide for security constrained economic dispatch without the carve-out for native load customers. They operate under joint operating agreements with protocols in place that deal with congestion management, redispatch imbalances, and loop flow.

They engage in intra and inter regional transmission planning and have mechanisms for regional cost sharing for transmission investments.

In contrast, the non-RTO markets which border RTO markets creates seams issues such as price distortions, which are created by loop flow from the non-organized markets that effectively reduces the available transmission capacity to members of the RTO.

It decreases FTR revenue because the parties creating the loop flow do not take congestion costs and suppress LMPs when the day ahead market does not factor in the congestion created by loop flow in real time.

Also, good reliability and congestion management are dealt with through the use of transmission load relief, TLRs, rather than relying on market sequels and price transparency.

Redispatch does not require third-party generation solutions where such solution may be more cost effective.  Also, there's a balkanized transmission planning, which perpetuates congestion.

There is no regional cost sharing, which can blunt any incentive to undertake the transmission investments, which do not disproportionately benefit the utility in the non-RTO market.

The independent transmissional or ITC -- I may switch between acronyms -- model is not equal to or superior to the planning process that exists in the organized markets.  While the ITO can validate and perform the transmission planning analysis and from my transparency regarding planning criteria, the base case model and annual plan, the ITO cannot compel investment to be made or eliminate transmission projects from which generation or demand management alternatives may be more economic solutions.

The ITO is advisory. It is not charged with taking a truly independent role in terms of developing a clean sheet approach with a view towards regional impacts, or the least cost to the end consumers.

In effect, the ITO has no requirement to coordinate across the seams and no teeth to compel facilities to be built. There are no economic drivers or processes in place to resolve seams issues which benefit the utilities in a non-RTO market.

No oversight of the cost benefit associated with remedying seams issues and to put in place joint operating agreements.

Ultimately, border utilities and non-RTO markets can import or export energy from organized markets when it is in their economic interests without paying for the costs associated with RTOs or ISOs as members of these markets incur for their participation in regional planning and cost sharing and avoid embracing a transparent pricing model, which relies on market forces rather than TLRs.

In conclusion, we are on a mission to exercise its full range of authority when there has been a request by utilities to withdraw from RTOs and ISOs, take such action in the context of furthering competitive markets or avoid the relative efficiency of creating new and mobile seams, assess the futures and comparability of the alternatives to be organized market before granting any approvals, and to further the goals of joint and common markets between RTOs, ISOs and non-RTO ISOs border utilities.

Thank you.

CHAIRMAN KELLIHER: Thank you. I'd like to now recognize Dr. William Hogan of the Kennedy School of Harvard University. Welcome.

DR. HOGAN: Thank you, Mr. Chairman. I appreciate the invitation to join you today in these continuing discussions about electricity markets.

As you know, I don't speak on behalf of anybody else. I'm just here representing myself.

I thought, at least in these introductory remarks, it would be useful for me to try to make two general points, opposed to talking about too much about the details of specific cases, although I'll be happy, to the extent that I know about them, to get into that.

The two general points have to do with how do you deal with seams as kind of a guiding principle because you are going to have them, as you said earlier on. The eastern interconnect is just too big to imagine having a single entity running the entire thing, at least in the immediate future.

Second is to talk about this question of non-RTO or RTO participation and downgrades, and people leaving and coming, and the stability of that model. Let me try to deal with them in reverse order here.

The first question is how to think about what we should be doing and what principles we should be applying in dealing with the use of seams problems.

Here, I have in mind problems that are similar to what Commission Adams was talking about, where you fail to have price convergence. But it's critically important that we think about price convergence at the same location so that the same location is viewed differently by the two different parties.

Having a difference in price as cost locations is economics. That's just because of the physics of the system and constraints, and all that kind of thing.

But there's an artificial problem if at the same location the two different entities see things differently because of some way the rules work or something like that. And those are the kinds of things that I'm thinking about.

I think the general principle is to, again, go back to what I talked about before, to choose little R regulation rather than big R regulation. And rather than mandating what people are supposed to do in particular, you should try to get the information and the incentives right so they get the right signals. And then when they make the choices, they get to do the right thing, the little R version of that.

In trying to figure out the right signals and incentives, what I would think, conceptually, suppose, in fact, the seams were not there. Suppose virtually we have managed to put this together as a larger market, a larger pie, and it was working efficiently, what would it look like? What would be the character of the information and the character of the signals and so on?

And then try as much as possible to approximate that. It won't be perfect because you're dealing with different entities and so on. But you should try to approximate that and then make the market make the choices about what they're going to do.

Let me give you an example of what I mean by that, which I think has actually been quite successful. It's an example that's been discussed here today.

This is the seams, particularly, the seam between PJM and the MISO RTO, and operating and dispatch and so on. When we used to talk about the crayons, drawing with crayons, getting up the crayon to draw the boundaries between these RTOs, we look at that mess that's there, look at the crayon drawing, and you look at what actually happens in the joint operating agreement between PJM and the MISO.

Essentially, PJM is making decisions on how to dispatch its system in order to relieve constraints inside the MISO. The MISO is making decisions on how to dispatch its system in order to relieve constraints inside PJM. They are not looking at this as a sharp boundary between them drawn by the crayons.

Secondly, there is compensation between them in order to make sure that, in effect, the prices do, in fact, converge, and that people are paying the opportunity costs on either side of that system.

That works very well. That is a cleverly designed system. It's not the same thing as having a single entity dispatching the whole area because they, obviously, have to focus on some of the constraints and not all of them.

And there's a little bit of that going on. So it's not perfect. But that's pretty far along the road.

As an example -- and they thought about it in exactly that way -- so this is not an undoable idea. It's not a principle without application, and we have such an application.

So think about it as a virtual larger market. What would it look like, them trying to design the rules around these seams so that they replicate that as much as possible.

Second issue that I wanted to address is this question about inside and outside of these RTOs. I think what you have today is something that seems to be inherently unstable. The inherently unstable problem is a combination of several things.

One, is the glass half full in designing the markets. We've talked about problems and things that are missing, scarcity pricing, how to deal with transmission investment and so on.

But as long as you have less than perfect market designs, you're going to have some issues there where people are going to be concerned about that.

One of the things that happens in that process is you've intervened in a big R way, or the equivalent mandate, the RTOs, or somebody like that to do it.

And then we get cost socialization because of that process. And you've heard Commission Adams talking about the transmission of cost socialization problem in New England.

And that creates an incentive because if there's something missing in the market that would then substitute it with a mandate, which was socialized, did not create incentives for them to go through something else, which they don't like. And they talk about leaving the RTO or something like that.

We've heard about Louisville before. Then there's another aspect. There's unstable incomplete markets, socialization of costs. And in the background, voluntary participation in all of these things.

There's another problem, which is an inequitable, or at least different allocation of the burdens on the entities. I told you I was going to get excommunicated. This is where I get excommunicated here today.

It would be one thing to say that we had multiple different ways to achieve our objectives, and we have different models for how to do that. And people can voluntarily choose which one of these models achieve our objectives, and then let them go back and forth.

It is quite another thing when we have organized RTOs to provide more designs that meet the test of undue discrimination at non-RTO markets which don't meet the test of non-discrimination and don't have the necessary requirements in order to meet that test.

It's not surprising that it's more expensive to be in an RTO. You've made it happen that way. And when you add that on top of the cost socialization, it drives people to think about leaving.

If that's not the case, if it were not the case, maybe the solution to this whole problem is just to let TVA take over the MISO if they're so good at running these things.

And it's not a problem of inequitable burdens and cost socialization, but rather just that MISO doesn't know what they're doing.

I don't think that's the case. I think what you have here is a fundamental difference in the way costs are allocated and a fundamental difference in the way burdens are allocated between these types of organizations that makes the system inherently unstable in a voluntary context.

Since I don't like voluntary solutions and I'm faced with a mandatory cutoff --

(Laughter.)

DR. HOGAN: I think focusing on trying to make the burdens more balanced to get away from the cost socialization and work on the market designs is what you should be doing.

CHAIRMAN KELLIHER: Thank you, Dr. Hogan. I'd like to now recognize Carl Monroe, Senior Vice President, Operations, and Chief Operating Officer with the Southwest Power Pool.

MR. MONROE: Thank you, Chairman. Thank you, Commissioners, for allowing me to speak to the issues that are faced by SPP seams with other parties.

We actually have seams with other interconnects, too, but I'm not going to deal with that today. We are the only interconnection with ERCOT to the east, and also a party to interconnections with the west. Those are minimal type issues. We deal with those on an as-needed basis because of the back-to-back D.C. ties.

But with Eastern to connect us, SPP does have seams with a variety of parties, and most of that has to do with the roles that SPP plays in its operation in planning an operable power system.

For instance, we're transmission providers, so we have seams with other transmission providers that are around us. We're also a reliability coordinator and we have seams with other reliability coordinators, which may not necessarily be the same as our seams with the transmission provider.

We also play roles as a regional reserve hearing group, as a market operator, a regional reliability organization, a contract service provider. We provide tariff services and a regional transmission planner.

Each of those have seams with other parties that are on our seam, but play the same roles in their areas. We found seams agreements to be very beneficial in the way that we deal with those issues. Particularly, we have a comprehensive seams agreement with MISO that continues to evolve, that take into account the evolving functions that we play and that MISO plays.

We have a very limited seams agreement with the Associated Electric Cooperative. We actually made seams agreement with Entergy and MAPP. I'll talk to you a little bit about the MISO seams agreement and tell you a little bit about what's involved in there with the seams agreement with MISO.

It does deal with reliability. It deals with economics and equity issues. For instance, for reliability, we exchange real time and projected operating data, real time SCADA data, operating models, extensive operation planning data, joint operations in emergencies, and voltage and reactive power coordination. And for economic inequity, and particularly to coordinate our ATC and AFC, we exchange generator outage, dispatch order data, transmission outage schedules, interchange schedules, transmission service requests, load data, calculate firm and non-firm AFCs, flow gate readings, dynamic schedule flows, configuration changes.

We also coordinate transmission generation outages at TRM. And it dealt a little bit with the congested management process. I'll tell you a little bit more in a minute. But it also deals with planning.

We have a coordinated regional transmission expansion planning section of that seams agreement. It goes beyond the regional participation and economic planning and cost allocation principles that the Commission had in its most recent 890 order. It contemplates not only optimizing the needs of transmission planning, but also looks at allocation of costs for network upgrades.

The seams agreement also covers market monitoring, schedule checkout, and treatment between operators.

For reliability, NERC really, with its mandated reliability standards, does actually ask the reliability coordinators in order to qualify to be a reliability coordinator to have a seams agreement with reliability coordinators on their border. There are just general guidelines on what they need to coordinate.

We think it would be better to have a more comprehensive and consistent reliability standard in order to deal with that seam and to deal with the agreements that reliability coordinators need to have, and they still perform the issues, whatever it's going to talk about, having to do with the differences between market and non-market operators and how they provide data on their flows to the processes within NERC.

Additionally, we had the six regional reliability organizations, including SPP that were in the Eastern

Interconnect Sinai Agreement last year to coordinate planning.  It's called the Eastern Interconnector Liability Assessment Group, and I think it will go beyond what the 890 order provided.

For equity issues, NAESB has dealt with seams issues before.  SPP was involved in that.  They're dealing with seams issues again and prioritizing high-priority items having to do with seams.

I'm not sure that it's comprehensive, but we would like to see that as a comprehensive list.  And we'll be working with the ISO and RTO Council to be involved in that process.

We'd also like to see them use the principles of the congestion management process, this in both the MISO SPP agreement, the MISO PJM agreement, and the PVA MISO PJM agreement.  That really provides consistency, not only for the real time information that we use to relieve flow gate congestion, but also the coordination with AFC and ATC calculations.

As part of our application, actually as a regional transmission organization, we were required to enter into an agreement with MISO.  And we support these types of agreements, not only for those parties that are operating markets, as it would with PJM and MISO, but also for all transmission providers that there will be a requirement to have a seams agreement. And that will be comprehensive to deal with, not only the reliability issues, but also with the equity and the economic issues.

Andy's covered a little bit more about the congested management process. This congested management process does allow us to look at impacts beyond our borders, to quantify the impact of all flows, to leverage the real time and new real time forecasted data for higher accuracy and redispatch to help relieve congestion.

Coordination starts about 18 months ahead of real time. So there's a lot that can be done ahead of real time to help manage the bulk power system.

We also like the focus of regional planning on FERC order 890. Our cost allocation methodology, as approved by the Commission, has increased the amount of transmission expansion within SPP, both through economic and reliability. We also have the responsibility under Entergy's ITC to also coordinate the activities not only Entergy's plan, but the activities of its impact on other transmission providers.

We also launched market operations on February 1st. As part of that, we'll be along external generators to operate within the market. So we're wrestling with the idea of what benefits those external generators would get from participating in the market.

We also are going to model those units as to where they are so we'll see the actual flows on the market. Steve covered the issue of FERC fees. I won't go into depth on that, but that is an issue with getting more participation in our RTO and membership in our RTO.

Again, a comprehensive standard seems a very good playing field for NERC and NAESB. However, our playing field for non-market operators in extending these principles of congestion management processes would advance the reliability of equity of the bulk power system.

Thank you.

CHAIRMAN KELLIHER: Thank you. I'd now like to recognize Mr. Jeffrey Gust, Vice President, Energy Supply Management, MidAmerican Energy Company. Welcome.

MR. GUST: Good morning. I want to thank you for this chance to address the Commission and its staff on seams issues affecting RTOs and the companies that border them.

MidAmerican Energy is a vertically integrated utility that serves bundled retail load in Iowa, Illinois, and South Dakota. We're also very active in the wholesale market in the Eastern Interconnect, making energy purchases and sales throughout the Midwest.

MidAmerican also borders three RTOs, either through physical connections or contractual rights. We have two 345 KV interconnections with Commonwealth Edison zone

PJM. We have a number of ties at various holdages with the Midwest ISO, and we have contractual interconnections with the Southwest Power Pool.

In 2006, roughly 10% of our wholesale energy sales and purchases involved RTO, day ahead, and real time market. In addition to these transactions, we had numerous bilateral transactions in each RTO footprint. We're also participating in the new contingency reserve sharing group involving numerous parties in and around the Midwest ISO.

Along with other RTO entities in the MAPP region, we participate in a seams operating agreement with the Midwest ISO. MidAmerican values its participation in all of these RTO markets.

Today, I want to touch on the benefits that border entities bring to these markets, and I want to assure you that we are paying our way.

Let's talk for a moment about the benefits that border entities bring to RTOs. First of all, external parties like when American maximized the overall economic efficiency of RTO markets. The price signal we get at our interface contributes to convergence between related energy markets.

Responding to these price signals has the overall effect of reducing aggregate costs across all interconnected energy markets. As a result, entities on RTO borders enhance market liquidity, and they contribute to the goal of dispatching least cost generation across all interconnected markets.

Second, market participants outside RTOs help alleviate congestion inside RTOs. Once again, the price signals of the RTO interface either encourage or discourages inpoints, depending on transmission congestion.

Comments like these might seem self-serving if I had written them myself. I didn't. Every one of these comments was made by the Midwest ISO itself to entities in the MAPP region at the December 8, 2006 planning conference, 2007 and beyond.

MidAmerican concurs with the Midwest ISOs' statement that entities bordering RTOs help increase efficiency and alleviate congestion. The Commission scheduled today's session in part to determine whether border entities are benefiting from services they're not paying for.

First of all, MidAmerican Energy does pay for RTO services. For example, as I stated before, the Midwest ISO serves as a reliability coordinator. The Midwest ISO performs that same reliability service for a number of other utilities outside its market footprint. We wouldn't expect that service to be free, and it's not. We pay for reliability services, and it turns up an agreement entered into freely by the Midwest ISO itself. In fact, that agreement creates certain economic disadvantages for us when compared to entities within the Midwest ISO market.

When the Midwest ISO redispatches generation within its market footprint for reliability reasons, those generators are paid for that operation. However, generators outside the Midwest ISO market receive no compensation for operating at the Midwest ISO's direction.

Second, when MidAmerican transacts with RTO markets, it pays for transmission service and admin fees just as any other entity that purchases and sells into the RTO market. In 2006, we paid almost $6,000,000 for transmission service on RTO systems.

The rates we paid for RTO admin fees are proposed by the RTOs themselves and accepted by this Commission. Every dollar that American pays in market admin fees is a dollar that doesn't have to be paid by an entity in the RTO footprint.

MidAmerican also has been a leader in helping shape regional policy. We recently helped to bring together a number of MAPP participations and Midwest ISO members to form the new contingency reserve sharing group by providing a broader means to share generation reserves. This effort has helped reduce costs for all participations, whether they're in an RTO market or bilateral market.

MAPP members have also negotiated a seams operating agreement with the Midwest ISO to govern operations of the seams between them.

MidAmerican believes RTO markets are continuing to improve. We have noticed that improvement with the Midwest ISO from its earlier days in 2005, and anticipate the new ancillary service market will also provide further improvements.

However, we want to encourage the success of RTO markets, and we hope they can create a strong business case for greater involvement.

There are still some issues that need to be addressed before that occurs. For example, limiting the rights of members to withdraw does nothing to create appropriate markets inside those inefficiencies. Neither does seeking to impose higher admin fees on border entities. Instead, these tactics would have a chilling effect on market activity between RTOs and border entities. In doing so, they would harm the RTOs own members. In short, RTOs and their border entities provide benefits to each other.

MidAmerican looks forward to continuing to work with its RTO neighbors. We believe RTOs are an important part of the current market landscape, and we want RTO markets to succeed.

Border entities like MidAmerican help improve the efficiency of the RTO markets. We help alleviate congestion in these markets. And when we participate, we pay the tariff rates proposed by the RTOs themselves.

Thanks again for offering MidAmerican the chance to make these comments. I'm happy to answer any questions you may have.

CHAIRMAN KELLIHER: Thank you, Mr. Gust. I'd like to now recognize Raymond Hepper, Vice President and Assistant General Counsel of the ISO New England.

MR. HEPPER: Thank you, Mr. Chairman, Commissioners, for the opportunity to be here.

Many of my comments have actually been made by others on the first panel and three-quarters this morning. So maybe I can keep this one short and leave time for questions.

I think the real question that Chairman Adams posed in many ways is is there a scene now within New England, and will there be if Maine would exercise its right to withdraw.

I think, to start thinking about that, I have to start where the Chairman started this morning. RTO participation is voluntary. We recognize that. It's been made very clear. We agree with it.

ISO New England has been working very closely with Maine to try and ensure that, as they do their empirical analysis to determine whether the benefits are worth the price that all the information is presented.

I think that's been a very productive discussion. It's certainly our hope and goal that, ultimately, Maine decides because of the benefits RTOs bring that they would like to stay as a member.

There's a lot going on and New England -- it starts from the premise that New England is probably the smallest, tightest power pool in the country. It's a 30,000 megawatts system, and it is very tightly interconnected. It has developed that way over 40 years now.

Maine has been a very important part of that. Right now, New England is looking very carefully at its future both internally and what it means to work with its neighboring regions. The ISO has started a process where Maine and other states, and a number of stakeholders within the market, and policymakers from the states and outside the region are looking at the scenario analysis to say what is New England's energy future? How can policymakers really frame that? It ties very closely with Chairman Adams' point on making the pie bigger.

Is it appropriate to look at Canadian imports, whether that's New Brunswick, Newfoundland, whether it's hydro connect, there are opportunities there. There are costs. The goal is to really look at those issues and provide feedback to everyone to make good policy decisions.

There are very major transmission studies going on with respect to Maine. Part of the benefit of the RTO is looking at that planning on an integrated regional basis, looking at what system needs exist to protect the liability. Looking at what exists in Maine to protect the liability. Looking at northern Maine, how it integrates or doesn't integrate.

Looking at its market, which is now a separate market, as Chairman Adams pointed out. Maine has itself recognized there are some problems with that market, with basically one supplier. Looking at all of those issues is important as we go forward.

There is both an empirical and a policy question that Maine is considering now and maybe here at some point, the invaluable question is the costs and the benefits question.

I think the dialogue Commission Spitzer, Mr. Kozey and Chairman Adams had really brings to the floor a lot of those points. I just want to touch on them very briefly.

It's very easy to look on one side and say, "What is Maine's transmission cost under a somewhat socialized transmission scheme." It's very hard to look and say what are the values of a liability, what are the values of all of the other functions, the planning functions and all of those things that are brought. They're far harder to quantify. But they're very real.

I think Chairman Adams pointed out to you correctly, Maine, more often than not, has been an exporter. But I think the more often than not is important.

And we see other times when Maine is an importer. When Maine Yankee was set down in the nineties, Maine got to rely on all the rest of the generation in New England through basically an open market and meet its energy needs.

Just last year, Maine became an importer when two units were closed down due to bankruptcy and other financial issues. Again, Maine was an importer. It didn't have to run its very large, expensive, oil-fired units to meet its loads needs. Those are some of the empirical questions you have to look at.

When Chairman Adams discussed transmission cost allocation, is it fair? Is it right? Does it work? I think the does it work question is being pretty well illustrated by the fact that we have had significant project built in four of the six New England states, and that the infrastructure is being necessarily inappropriately upgraded.

You've got the load pocket in Boston being significantly relieved by building transmission there.

You've got Vermont being improved. But importantly, for Maine, as it looks at it, you've got $100 plus million dollar project that's the second timeline between New Brunswick and Maine. That's being paid for as a reliability project.

Ninety-two percent by the rest of New England, 8% by Maine. Now, certainly, significant benefits for reliability for the whole region, and when you look at the question of the beneficiary paid structure, it is a very amorphous and difficult question. Those Connecticut benefits from a second New Brunswick tie, those are Maine benefits from an improved transmission system in Connecticut. Our answer to both of those is, yes, and those have to be looked at very carefully.

As Maine looks at it, as you look at resources, Chairman Adams described Maine as a resource state, yet markets seem to be working in ways that many of us expected to be working.

As you're well aware -- and I won't talk about the proceeding that's in front of you now -- under our forward capacity market rules, what the market is going to prove by this Commission, we've gotten a huge show of interest. We know everybody that's shown interest won't come.

Most of their interest in putting in new generation facilities is in Massachusetts and Connecticut. So, in many ways, the markets are working. There's much less interest in building generation in Maine relative to the rest of the region.

Given all that, I think there are, right now, you're seeing, as Dr. Hogan pointed out -- you're seeing price differences that are rational because of economics. You need to look at the whole balance as we move forward and work with Maine to look at the future and whether there will be seams.

Thank you.

CHAIRMAN KELLIHER: Thank you, Mr. Hepper. We have 50 minutes. I think that divides into 12 minute increments. Why don't we change the order and start with Phil this time.

And I want to work the staff and I'm going to give the staff my time at the end. Why don't we start with Phil.

COMMISSIONER MOELLER: Thank you, Mr. Chairman.

Dr. Hogan, it seemed to me like you have more to say. I want to give you a couple of minutes to do that now.

DR. HOGAN: I don't know that I have a great deal more to say about the general principles. It now gets down into the question of how you implement them.

I talked about the burdens not being shared equally across. I talked about that in the past. There's a long list of things, but if I had to pick the one that was the most important, the difference between the RTO and non-RTO, it's access to the balancing market in a non-discriminatory way.

That is an important principle. I think it's a necessary requirement for non-discriminatory access. And therefore, you have to do it if you claim you're providing that.

It's blatantly different now. It also is consistent with a notion I talked about of what would the virtual market look like? It would have, amongst other things, lead cost dispatch across the region. This wouldn't be a perfect approximation of that, but it would certainly get you closer in that direction. So it's consistent with the overall argument.

If I had to pick one example of something like that between RTOs and non-RTOs that was a difference in the burden that they face, one does this and the other doesn't and is not required to do it.

Conceptually, if you have a way of meeting your objectives and it's more efficient than others, then people would choose it.

If you start imposing different costs and different burdens in addition to that, someplace you're going to get a tipping point. Then they'll say even though it's more efficient to do it with a larger party, I'd rather not participate, thank you very much, because I have to pay these other costs and these other burdens. That's a delicate balancing act for the Commission here.

My temptation constantly is to say, well, if you're going to tax people, you have to make it mandatory.

I don't go that far in this case because I do think there is this great discipline to having a voluntary. At least there is the possibility, if it gets completely out of whack, that people could leave and go someplace else. But I think it's not the intent of voluntarism to say we're going to have two parallel systems, one with high costs and high burdens. And another with lower cost sharing and no burdens. And we're going to make it voluntary. Which one do you want? Which is the current situation, I think.

I think that's unstable.

COMMISSIONER MOELLER: Given that dichotomy of the voluntary nature that we just talked about, the questions I asked on the last panel related to getting the greater granularity of flow data as an interim measure, what are your thoughts on that for improving at least as we see it, the accuracy of price signals, given that it would still presumably be done onto a roughly voluntary system of RTO membership?

The voluntary nature of that data is another question. What are your thoughts on that?

DR. HOGAN: I think that's the right direction to go. In fact, I don't think it, in itself, is going to solve these problems, and I wouldn't put it as high on my list as non-access to the balancing market in the same way.

But in order to implement the balancing market in the way I'm thinking about, you have to use the granularity they already have, which is much greater than that, which they're reporting.

In that sense, there would be much more transparency about what's happening, the choices that are being made and so forth. And one of the reasons that I like that as a step, that balancing market, is because there's a transparency.

To review a lot of the things that you're talking about, and part of that package would be -- and I'm talking about within a control area. When you're talking about scheduling between the granularity, information could be provided in order to make it easier to coordinate across those areas. But you could also explore that within the control area.

COMMISSIONER MOELLER: Thank you.

MR. MONROE: Thank you to all of our panelists. Thanks for the participation.

COMMISSIONER MOELLER: But I think we need to, I guess, congratulate you for the successful launch of the market on February 1st. I don't think I've adequately done that myself.

Do you have any observations, in general, post-February 1 that you want to share with us?

MR. MONROE: Actually, it is a big shift to open a balancing market. It is a big paradigm shift to the parties that are in the market itself.

We've had about a month and a half of operations now, and we're still learning reactivities that are required for operating the balancing market as well as working with the market participants in educating them on how they can better participate within the market.

It's going really well in our case. We see the benefits that are flowing, even from day one, in the balancing market to those parties that can participate in the balancing market. And, again, we'll be looking at this external generator to include those within the market.

COMMISSIONER MOELLER: What's your timeframe on that?

MR. MONROE: Six months. The Commission asked us to do that within six months after the start of the market, so we're looking at that. I think we will or have filed to extend at least the para filing by one month right now.

COMMISSIONER MOELLER: Any other surprises, both good and bad, that you want to share with us in terms of what you found out?

MR. MONROE: Not a lot of surprises. I think we did a good job of thinking through things. We had delays based on trying to think through some of the -- both the liability and economic and equity issues in the market itself.

More visibility of information to the operators -- both or all operators -- and to the market itself. There's more information that they need in order to make wise decisions and for us to make wise decisions. So we're learning from those types of experiences, but no real big surprises so far.

COMMISSIONER MOELLER: I guess we really haven't talked a lot, although there have been references to regional transmission planning and the fact that some areas are already going forward prior to our order 890. But we've obviously encouraged it through 890.

I guess I'd like each of your reactions as to what you feel the prospects are for improved regional transmission planning. I guess to the extent that it can address these issues going forward.

Ron?

MR. MUCCI: Thank you. I think we do see, as I pointed out, a dichotomy in that currently. I'll use MISO as an example.

They have a process they call NTEL, which is a very vigorous way, a thorough process where they, in essence, from sort of bottoms up, look at all the projects that are put on the table.

At the end of the day, the Board can approve those projects. In fact, they have approved their last plan.

While I've certainly not seen what the compliance would look like, with 890, I do have at least some concerns or reservations based on the experience to date. But for the non-RTO markets, that planning can get rather narrow in scope.

In deference to SPP, I have sat through the ICT process, where they're working with Entergy. I know this is eastern, but I'll segue way a little bit over there.

There are some critical issues with respect to what transmission investment would be necessary to reduce from our end some fairly high costs, RMR units.

So as I'm seeing this process evolve, at the end of the day, as the independent coordinator, you can opine, you can run the math and say, yep. That coal mine model really works. But you can't compel. I think that is a stark difference.

Regional planning to chap to converse and compare notes or to what extent is there going to be investment made that will improve the regional flows?

That's what I was trying to allude to briefly in my comments. As you look at regional planning, you have to look at the piece. Where is the ultimate decision maker in order for approval?

I've broadened that scope to also suggest that you have to look not only at -- and I'm speaking about the Ohio example earlier. But I think there's a little wrinkle here in that generation in demand response, by the way, can be thought of as substitute goods for transmission investment.

I think you've got to look in that kind of broader scope. Indeed, you need to look as broadly as you can, again recognizing there won't be one big region. But you've got to have that kind of collaborative effort put together, because at the end of the day, in MISO's case, that was over $3,000,000,000 over an extended period. It's not an annual figure, but these are sizeable investments in the transmission system. And I think we can ill afford to have meetings where cookies and rolls are served. But where the really tough decisions are made as to where those investments are going to be made. But there are going to be tradeoffs. The reality is, there's going to be some tough decisions to be reached.

I'm very hopeful that as 890 is implemented, we'll see that process evolve in a constructive way. But I would just admonish the Commission to closely watch that process and to see where the decision making ultimately rests.

Thank you.

COMMISSIONER MOELLER: I guess I want to hear from the rest of you, but I'm also sensitive to eating into my colleagues' time.

CHAIRMAN KELLIHER: You have one minute.

(Laughter.)

COMMISSIONER MOELLER: I'll wait to hear your answers privately.

CHAIRMAN KELLIHER: Thanks, Phil.

I'd like to recognize Commission Spitzer.

COMMISSIONER SPITZER: Thank you, Mr. Chairman.

Mr. Mucci, you brought up the substitute good argument with regard to generation and also demand response with respect to transmission.

It seems to me that if you've got price signals under the current regime within the RTO ISO, you've got this assumption that there's non-discriminatory adequate transmission, and that's obviously problematic in some respects, more so with the adequacy.

So I'm not -- certainly I'd like to rebut. I'm not sure we have free substitution. It seems to me that among the most significant diseconomies are the absence of transmission and the fact that the lead time for transmission varies. The economic signals vary. There is uncertainty. The deciding process is attenuated.

You've got all these reasons why transmission doesn't get built. That creates ultimately a circular problem here. What lawyers call renvoi where you've got jurisdictional distinctions more pronounced in the east because of the size of the jurisdictions being small, proliferation of entities notwithstanding, regional planning, and order 890.

These might be in terms of creating the root cause of the seams' continued existence, to put it most simply. So in what manners, assuming we're not going to go forward with any type of joint ownership.

But joint planning is where we're at. In what ways can cost border? Maybe Mr. Gust will work on eliminating some of these diseconomies through transmission. That would make your life easier, make more demonstrable the benefits to Midwest ISO, and create a situation where the pie is expanded, as Chairman Adams suggested.

MR. GUST: I'm not on the transmission side with our company, but I'll make some comments anyway.

I would agree with my colleague earlier, Larry Thorson, that at least in the MAPP region with a rich history of joint planning, you know, I think if this makes sense, as a company, we also have a rich history of joint planning, both on the transmission system and on the generation. In fact, we're in the process of bringing on a large fired plant. That should be online here in early summer. And we have 14 other owners in that plant.

We also had to build some major transmission to get that plant online, and we cooperated with our joint owners and with the region to do that.

So I don't know if we see some of the same problems that others do about joint planning, but those are my comments on that.

Mr. Monroe, you've got a nascent market here with a lot of moving parts. It's a challenge.

MR. MONROE: For planning, the issue with planning in 890 is 890 does encourage greater cooperation, greater transparency in the planning process itself. But it doesn't deal with actually trying to create that price transparency out into the future. The markets that we have today and all the ISOs and RTOs really create a lot of price signals in real time that you can use as a historical basis for looking at prices and give some price signals into the future. But it doesn't give those price signals into the future.

One of the things that our state Commissions, and we've had a real active regional state committee group that works together. In fact, they were the ones that did this cost allocation proposal for transmission expansion.

They're working together and they're actually exploring whether there should be a regional, even integrated resource planning process that would deal with both the issues of generator siting, generator fuel mix, demand response, other things that would look at those as substitutes for transmission.

You have to substitute those in the timeframe in which they've become substitutable, which is out into the future.

As we know, transmission takes three, five to seven years to build. So you have to look into that future to actually make it a substitute for that.

So from the planning process, that's what we at SPP are looking at. We do a plan every year for reliability purposes. In that plan, we also look at all the economic projects.

We have at least one other project that a party has stepped up to build on the economic side, even though they take the full cost responsibility. And right now, when we get the credits back from the transmissions that's sold to use that facility, we only get back.

That's not really, I think, a full incentive for transmission building for economic purposes. But we're also looking with the state Commissions for other mechanisms in order to enhance that capability of looking into the future and carrying what's best to locate.

COMMISSIONER SPITZER: Mr. Hogan, I earlier used the interstate highway analogy with some philosophical distaste because you had the government creating the predicate for the market, rather than markets existing and forming the shape of government actions.

So it's a little bit counterintuitive, but why don't you explain how you would attack some of these transmission constraints, absent the, frankly, very government intrusive model that was adopted in the fifties with regard to highways?

DR. HOGAN: I think that the transmission investment conundrum is the hardest problem to address in the framework that I've been talking about in this balance between the government and then the prime initiative.

I think one of the great difficulties, first off, is I'm all in favor of regional joint planning and studies and so forth. So I think chanting is undeniably a good idea, and sharing information and transparency and all of that kind of thing.

I think the dilemma comes when you confront this issue about going beyond chanting and mandating that things actually get done. Then how do you deal with that?

I think it's a mistake to argue that chanting is enough. I think it's a mistake to argue that mandates are always required.

The two ends of the spectrum, where at one end of the spectrum, you're only talking and there's nothing else happening isn't going to solve all the problems. But that does not mean that the only alternative is to set up a system that requires everything to be mandated.

Integrated resource planning where you're mandating transmission, you're mandating -- pretty soon, you'll be into mandating generation. Pretty soon, you'll be mandating demand side response.

In order to get all these things done in the same timeframe, that's where that goes. I think the real challenge is to design something that draws a line between those in a way that is sustainable, and how to actually deal with that.

I'm happy to go into some length. Actually, I've written a lot about this, but let me just give you the shorthand version of this thing.

The place where mandates are going to be necessary is essentially going to be in projects that are very large and lumpy, and have very widely dispersed benefits. They make a material difference to how the market actually performs. So it's very hard to capture the benefits at the margin. You can't do a little bit. You've got to do it all or nothing, and it's going to affect all kinds of people all over the place that are hard to get into the room.

That's the end of the spectrum where you're going to need mandates. The end of the spectrum where you don't need mandates, if you can get the price signals right, is where things are the opposite, where it comes in small lumps, small pieces, where it doesn't affect everybody. It only affects particular parties, and you define property rights in such a way that they can capture those benefits.

The trick is to design a workable system that distinguishes between those cases and sets something up.

I think an adaptation of the system that was developed in Argentina, the Argentine model, or something, which has not been given enough attention in this country, but I think actually has very powerful operational features which make it attractive to doing this.

The essence of the Argentine model is, first get the prices right so you get the scarcity pricing right and all that.

Second, a thing they did not do, that they should have, but it's amazing it worked at all, is define the property rights. That's the FTRs, the transmission rights.

Then set up the decision making process that distinguishes between the smaller investment and the really big ones. That's what they did.

Then for the really big ones, you have to worry about the problem that the RTO, as much as I have respect for the RTOs and the ISO, it is possible conceptually -- it's never been my experience, but it's possible that Andy Ott could be wrong.

You have to leave open that possibility. And the advantage of the RTO model is that the Argentine model is that you do the best studies that you can. You calculate the benefits as best you can. Then you assign the costs as best you can that go along with the benefit.

So you deal with the fact that Maine is concerned about. And then, finally, you let the people who are going to have to pay the costs vote about whether or not to go forward with a particular process.

And they have decision pools for this. There's the 70/30 rule. If more than 30% of the beneficiaries vote against it, you think that maybe the RTO is wrong and isn't such a good idea.

But if you can't get more than 30% to go against it, then you go forward, and you make everybody pay. That's the mandated part.

COMMISSIONER SPITZER: How do you deal with the temporal issue I addressed earlier? Maybe in a very short-term analysis, it may be desirable, for example, to withdraw from a RTO. The political pressures being what they are tend to overestimate or exaggerate the short-term consequences.

And in 70/30 --

MR. HOGAN: The first thing I would do is to get the scarcity pricing right. If I can get for short-term decisions and further anticipations on the long-term decisions, that's going to have more effect on that than anything else.

When you get down to the transmission investment question I think there are cases where you're going to have to mandate it. If it were not true that would make my life easier. But in fact there are. But because of that you don't want to have to set up the system which puts you on the slippery slope of having to mandate everything. And that's what the barrier is there that you're trying to create with that adaptation of the Argentine system.

So it's not perfect. I'm not arguing that it is. But if you think about it it means that you don't have to go into mandating generating and you don't have to go into mandating demand side response because they don't meet the test of being large and lumpy, almost by definition, particularly the demand side response. There may be a few cases in generation where that's not true. That would then narrow the scope of where the government has to mandate it.

CHAIRMAN KELLIHER: Thank you, Dr. Hogan.

I'd like to recognize Commissioner Kelly.

COMMISSIONER KELLY: Thank you, Joe.

I'd like to ask all of you whether you see any significant downside to setting up a regime to encourage RTOs and their neighbors to look at loop flow problems and the allocation of costs, and better allocation of costs connected with that. Any downsides?

Ron?

MR. MUCCI: None that I can think of. I don't know.

What I was thinking about is there are currently joint operating agreements in place and certain protocols that exist. But that will do a major disruption to where those issues are being focused on because we did hear this morning how MISO and PJM went to the point of bringing in the broader circle. I don't see a downside to having that dialogue because that is something, as I pointed out, that loop flow is causing pricing distortions.

Thank you.

MR. HOGAN: The principal downside in my mind based on not theory but experience would be temporizing. This is a good excuse to have a conversation for a long time so we don't have to talk about the real problem.

If it means we're not going to get everybody into the non-discriminatory balancing markets and we're only going to delay that until after we figure out how to deal with loop flow without having that, then I think there is a serious downside. I've always been concerned about that.

We have all of these policies we're implementing on transmission investment, capacity markets, better ways to do ATC calculation. We could spend another decade having conversations about things where we ignore the elephant in the room. But the elephant in the room is what that market would actually look like with the kind of thing that SPP is doing. And that happens in these RTOs.

COMMISSIONER KELLY: Let me ask you along those lines, short of requiring everybody to join a market, is there anything that would advance the non-discriminatory access?

MR. HOGAN: You have to provide balancing services. That is unavoidable. Everybody provides balancing services. You want people to be compensated for providing those balancing services. It's not like we're inventing something here.

All I'm saying is just do it in a way that's economically efficient, so that it's non-discriminatory. That is a very small step compared to going and setting up the full-blown operation of a market, the FTRs and all the other things that flow from that. But it's a necessary first step. It's the most important first step. And if you don't do that the rest of it is just temporizing.

COMMISSIONER KELLY: Thanks.

Carl?

MR. MONROE: That's actually what a balancing market is, is that type of setup.

To deal with your question about whether there's a downside to those types of discussions, the only thing -- I would agree with Dr. Hogan that they should have a goal in place. You just can't sit people together and say, 'Talk about these things,' without putting a goal in place.

Our goal as SPP would be to have a more comprehensive Seams agreement that would real with the loop flow issues in the same way that we feel has been very efficient with the other parties that we have with that. So as long as we have those types of goals I think there's no downside to that.

COMMISSIONER KELLY: Jeffery.

MR. GUST: I don't see a downside.

I just reiterate, in our region we're bordering three RTOs so we're going to have a lot of discussion. What I didn't mention is to the west it's a lot of public power entities that we have to deal with. We're trying to bring those groups together with us to work with all these parties.

We favor an approach where we can work with each RTO and work on an agreement like we have done at MAPP with MISO.

CHAIRMAN KELLIHER: Ray.

MR. HEPPER: I would probably echo Dr. Hogan's comments. It's certainly not the biggest problem for us.

If I can take thirty seconds to sort of make a broader comment, which is the entire planning process, we're far from perfect. I think our planning process, though, is offering a whole lot of benefits in terms of both having -- because of our structure we have the ability to mandate people to build true reliability, which is really a huge benefit and really -- in the capacity market we look at transmission as I shouldn't say a last resort; but if the market can come in with a solution to avoid a transmission need, you can have generation or demand side meet that need instead of transmission.

From an inter-regional point of view, among PJM, New York and New England, we're doing a pretty good job in trying to look at issues. But again, is looking enough? I think we all have to look at that in the long run.

COMMISSIONER KELLY: Thank you.

Carl, you talked about the provision of data between RTOs and non-RTOs, or ISOs and non-ISO members. Are there any difficulties that you've experienced in the provision of data?

MR. MONROE: The biggest issue there that we have is not the provision of data.

To get reliability data -- Most of the reliability data we get that's required actually in the NERC standards to be provided to reliability coordinators, we can get that data. The real issue we focus on is how that data is used in order to calculate loop flows and the impact that people have on each other. Then when you get into the TLR process how that actual TLR process uses that information to determine who should be curtailed and who shouldn't be curtailed.

So from the perspective of getting data, we haven't had a lot of issues with trying to get the data exchanged. It's a matter of how that data is used in the NERC process.

COMMISSIONER KELLY: Thanks.

I think that's it for me.

CHAIRMAN KELLIHER: I'd like to now turn to Staff and point out you're using some of Commissioner Kelly's time and my time, so we have high expectations.

(Laughter.)

MR. KELLY: I actually have one question and then I'll defer to Udi.

Professor Hogan, you mentioned at the last conference the Argentine model. How do you translate that in the United States? One way would be to take the RTO as the region. We assume that's what you meant. If the 20 percent who voted against it had to pay anyway and exit the RTO it might not work. On the other hand, you could say 'I meant to spread it across the entire eastern interconnection.' That may be very wide-spread socialization.

Are there some natural regions that someone --

the government or whoever in the planning groups would define so everybody in that region would have to pay whether they're in an RTO or not?

MR. HOGAN: If I were in charge of setting up the rules for this I would not restrict it to RTOs and not restrict it to their regions for the obvious reasons you're pointing out. It's very important. This is a beneficiary-pays model. So the allocation of cost is to the beneficiaries. The votes are allocated to the beneficiaries, not to the people who are disaffected.

If you take the Maine example there would be costs allocated to the generators and votes allocated to the generators in Maine but not to the load. The load, because it loses in this process, as Commissioner Spitzer was talking about before, we have trade in some regions and some regions are shot and so forth. Nobody's ever going to do anything if you say that the people who lose could get to stop something like that. So you would identify the beneficiaries.

It's not socialization; it's quite the opposite. But there is the problem that even without socialization of the cost and assigning to the beneficiaries, if you have very wide beneficiaries and they can opt out then they don't want to pay either. They let somebody else pay for it.

It's not going to be perfect, obviously, in terms of this is rough justice, trying to calculate these things. There may be situations where the answer is when we do the cost-benefit studies under different scenarios -- which we have to do in order to justify it in the first place, right, because we don't want to build things that are not economically beneficial -- we see that the beneficiaries flop around a lot and it's very difficult to tell on an expected-out basis who it is; then it's everybody. By definition that's what that means.

But it's not the case in most transmission investments that that's actually true. The notion that southwest Connecticut upgrades have the same effect on Maine customers as they have on Connecticut customers doesn't pass the laugh test. It's obviously not true, and that's something that comes out of those calculations when they're doing it. And you recalculate it for every project, who the beneficiaries are and how it's going to be allocated.

I don't know how the MISO -- I don't know the details of this issue, but this 80-20 scheme that was developed for MISO -- and I don't know if they're going to implement it but they've got 80 percent of it at least in the beneficiary phase category -- that seems to me to be a good direction to go in that sense, but it would not be restricted to the RTOs. Otherwise you'd have exactly the problem you're trying to avoid here.

So I would say anybody could come forward and nominate a gargantuan transmission project and go through -- in front of you and then say, 'Here's the cost allocation that we get,' and then we'd have a vote by the beneficiaries.

MR. KELLY: Let me just follow up. I'll direct it at Mr. Hepper.

I've always thought an advantage of the New England system was that it was almost a formula. You would know up front in the planning process who would pay so you didn't have to do a case by case litigation of who would pay, which might ultimately stall the planning and construction of a line.

Mr. Hepper, what do you think?

MR. HEPPER: I'd be strongly inclined to go back into private practice.

While I think conceptually -- I'm not familiar with Dr. Hogan's Argentine model -- I think in New England one of the things that was taken into the balance was precisely your point. The thought of coming here on an ongoing basis on large transmission projects to decide whether somebody is a 76 percent beneficiary or a 68 percent beneficiary is the reason for my quip about going back into private practice. It is one of the big benefits of New England's model. Nothing is perfect except a cost allocation where somebody else pays every time.

But that is one of the huge benefits of New England's model, to really have it predetermined by formula. It's worked and gotten transmission built.

MR. HOGAN: It's easier to do it by formula. There's no question about that. And it's going to be an unpleasant conversation.

I would actually give the RTO the responsibility for figuring out these proportions. But understand, in Argentina -- and Argentina is not the United States -- but Argentina under the system built a lot of transmission. It was all built on the economic basis where people were taking the risks and building it and paying for it themselves.

They had one big project that was stalled under this process because they couldn't get the votes for it. And it was uneconomic. It was actually a bad idea. So it worked. The planners liked the idea of building it. But when you actually did a sharp pencil to the analysis of the economics it really wasn't a good idea to build with. It was delayed and delayed and delayed.

It finally got built, incidentally, after the government took over. They had a change in government. They said, 'We don't like all this market stuff. We're going to take government subsidies and build it.' And they built it.

So that's easier. There's no question about it. But then it puts you back in the soup because now FERC is going to have to worry about demand side. They're going to have to worry about making sure that that gets built. They're going to have to worry about generation because they have no way of drawing the line that prevents having to mandate everything, other than being just arbitrary.

MR. KELLY: I'd like to defer to Udi Helman.

MR. HELMAN: My question is for Mr. Monroe.

As you look, you're in quite the mix of a number of seams agreements. As we look at the market to non-market agreements we're going to hear on the next panel that the MAPP-ISO agreement is about to be renegotiated and that will take some time. Can you give us a sense of what you think the learning curve is on these sorts of agreements and whether there is a best practice at this point, or whether you're still sort of in the middle of working out how to organize these sorts of agreements?

MR. MONROE: I think we're in the middle of evolving these types of seams agreements in order to reflect realities of what we're finding as we go forward with operations, and as we change our operations, too, and improve our operations, both markets and non-markets. But the experience we've had -- and again, this is experience based on really us having a Seams agreement with MISO and us involved with a group that is looking at these, at least from the particular aspects of this congestion management process, that group looking at improvements of that whole process, and that includes both market and non-market entities, that learning curve is not that swift based on the IDC proposals and the way people deal already with loop flows between each other.

It's a matter of agreeing to accurately reflect into those types of tools, those types of information exchanges. What actually is happening right now as opposed to using the previous models. And also taking responsibility for the impact you have on somebody down to some percent, whether it's zero or three or five, just make it common to everybody so that we can all take those effects into account.

The seams agreements themselves, all the concepts have been talked about. Outside of this congestion management process there's a whole lot of other Seams issues that deal with liability. From that perspective a lot of these are well known things that are already done. It's just a matter of sitting down and agreeing that you'll do those things and that you'll spend the time in your organization. And a non-market organization is actually making decisions on how to implement those things.

MR. HELMAN: So when you advise FERC, as you do in your comments, to support standard agreements you have an idea on the congestion management and what you think that standard approach should be?

MR. MONROE: Yes. We feel like at least that forms the basis for standard agreements, the CMP process for loop flows and for the capability of being able to determine what impact you have on others.

And then the CMP process goes further and determines the rights that you have on other parties' facilities, too; what they have on yours and you have on theirs. So that forms the basis. Whether that's perfect or not, I don't think so. We're evolving that as it goes forward. There's work on that. But it's better than where we are today.

MR. HELMAN: Just a very quick question for Mr. Gust.

You heard some ideas from some of your neighboring RTOs about either increasing the administrative charges of selling into the market or possibly restricting parties from getting the LMP at their boundary unless they provide certain information. And then in your comments you were concerned about costs that you feel you bear unreciprocally with the RTO markets.

Do you see a model in which these various pieces can come together in a way that's acceptable to you and that results in a high degree of coordination or these zero sum situations?

MR. GUST: I don't know if we see a standard model.

But I think what we would pursue is working out our differences with each one and working them through these seams agreements or other mechanisms. We think we can work through them. And we think we can get to some end that both parties are satisfied. So that's what we would recommend.

CHAIRMAN KELLIHER: Any other questions?

(No response.)

CHAIRMAN KELLIHER: With that, I have one question and then we can take a break.

I just want to ask about flow gate information. Are there best practices? Is there one arrangement that really stands out as the best way to share flow gate information between RTOs?

MR. MONROE: The best example that I have is the CMP process.

Actually each of those agreements that we've talked about has attached to it the congestion management process. That's actually that 18-month window where you're actually sharing information 18 months out, all the way up until real-time and actually determining not only the sharing of that information but who has responsibility rights on different facilities. And so for the paradigm that we're in with flow gate, the way in which we evaluate transmissions based on flow gate for short term and the way in which we operate the system, the way in which we curtail transactions are all based on that, each using the most constrained facilities. That's the best that we've found so far in order to be able to both share the information but then use that information between each other and at the IEC in order to make those things consistent between each other.

CHAIRMAN KELLIHER: Thank you, Carl.

With that, I'll dismiss this panel. We're going to resume promptly at 1:30.

I apologize we're not able to offer you lunch today. We are operating under a continuing resolution that forces certain economies.

(Laughter.)

CHAIRMAN KELLIHER: that may force you to experience scarcity pricing at the Sunrise Caf .

(Laughter.)

CHAIRMAN KELLIHER: See you at 1:30. Thank you.

(Whereupon, at 12:25 p.m., the Technical Conference in the above-entitled matter was recessed, to reconvene at 1:30 p.m., this same day.)

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

(1:35 p.m.)

CHAIRMAN KELLIHER: I want to thank the panelists for being here so punctually. Why don't we begin at the beginning.

Let me recognize Michael Kormos, Senior Vice President, Reliability Services, PJM Interconnection.

MR. KORMOS: Thank you, Commissioner. Thank you for the opportunity to speak to you today.

I wrote down a couple of things that I wanted to talk about. Number one on the list, as you can imagine, was loop flow and contract path methodology. And I'm trying to add a little bit to the discussion, try to add a little bit more of what we're doing with MISO and why I think that has been much more effective than what we were able to do on other Seams.

We wanted to mention -- talk a little bit about the redispatch options and really having an operationally efficient redispatch. I'll mention long-term planning and information sharing. I don't think I'll go too much into those with the time.

I'm encouraged by Order 890. I'm hoping that will obviate some of the transparency issues both in the planning and the transmission side.

Regarding loop flows and sort of the historic methodology we've been struggling with with TLRs, I think the bottom line is when you look at it the result of it is it does discourage economic transaction. It's actually a hindrance in my opinion to maintaining reliability except as a last resort. In reality it forces most parties to protect their own economic interests at the expense of others.

We can, if we can compare and contrast it to what we've been doing with MISO now in our congestion management process, which was the CMP mentioned -- it's a much better model. I think it's a much better operational model. Just to give you an example of what we're doing, right now we actually limit the sales of our transmission service by monitoring over 600 flow gates for any potential impact. We actually accept the third-party's calculation on those flow gates. If it's not available we will calculate it for them and voluntarily limit our transmission service that we sell if we go over the limit on those flow gates. And again, for the most part we're doing this unilaterally.

Also, as Andy mentioned, we track explicitly every megawatt from every generator. We actually do it every five minutes. We calculate the flow and we track those flows in over 450 flow gates. And we will in fact redispatch to service.

Some of the other things we're doing, including with TVA in some cases, is we go beyond just a plain looking at AFC and seeing if there's room. We also developed a historical allocation sharing methodology. We actually have allocated the flow gates to all the parties involved in the CMP.

I think that's really one important point I want to take a moment and just stop and point out. Tracking the flows is a great first step. But unless we can get agreement as to how much you're allowed to impose on your neighbor through loop flows and get a commitment level, it's not going to necessarily matter. We'll be able to track it and we're hopefully providing better numbers, but we need the allocation methodology. And that's what we've developed through the CMP.

The next step further we went with MISO is not only we tracked it and allocated it, but when it comes to a constraint we've actually come to the point where we can redispatch each of the resources so that ultimately we are focusing on the most effective dispatch and not simply for curtailing contracts. That's going the farthest of that.

I realize that one of the biggest hurdles in doing this is we had to move from the contract path methodology and look at actual physical flows. The MISO model and the PJM model obviously lend themselves, are models that are based on markets that are based on physical flows. If you look at what we've done with TVA, I think it does show you that you can do this in areas that are not using LMPs because, again, we obey the laws of physics. We are still tracking flows based on those laws.

If we look at our borders there's a couple of issues we have. One, as Andy mentioned, is the generation-to-load dispatch and the fact that right now it's basically simplified to a simple peak load calculation. And we basically ignore the fact that everybody's control area dispatch changes continuously throughout the day.

What's happening now, particularly without the planning side of this -- again 890 will correct that -- is as people look at adding new resources they're simply looking at their own system. And if they can put in another system they make it firm and it basically becomes firm on all of our systems, and we don't necessarily have any recourse as to what we can do about it. It's basically hidden behind it. There's no transparency as to what the dispatch does and we're forced to accept the flows that the systems impose on us.

I really would like to think there's a fairer way to recognize, a way for people to do that economically without overburdening another party.

Order transactions on point to point have similar problematic issues with them in the fact that again it was done on an aggregate basis. There's no true attempt to try to determine the actual resources.

And again, just as a simple example, going back to what Andy said, you look at a control area transaction right now. We're forced to aggregate it to a control area level and assume that all generation has the same effect. That's really not true. It really does matter what generator is going to load to support that transaction. A generator close to our border?

Obviously we put more loop flows on the system. One further away will have less impact. By doing these control area approximations -- and some control areas are fairly large -- you can obviously get some missed flows there. When, as we've done also as part of the CMP, we will actually report to the IBC our marginal unit. We will tell them which is the next unit we expect to load or unload on what part of our system so they can try to capture the true effect that our dispatch has on them.

As mentioned before, contract path methodology has caused us numerous problems. We've seen attempts to basically gain our system and make it operationally very difficult as people who have scheduled on a long contract path take advantage of some of the interim pricing we have and yet the flows are someplace else. We've tried to take steps to correct it. But again, I think we're sort of running out of options on that.

I would like to mention the redispatch. That's obviously the next step on this. After being able to track it, being able to allocate it from an operating perspective, I still am bothered by the fact that we ignore the fact that we can solve and maintain reliability by dispatching the generation close to the constraint, which is more effective and easier to do. If we do it through TLRs where we're trying to move hundreds if not thousands of megawatts of generation, which are hundreds if not thousands of miles away from the constraint, ignoring the fact that there are better redispatch options from an operational perspective, I'd really like to see us go through that.

In closing, I would emphasize that we not really look at tweaking the TLR approach. Hopefully there's a greater willingness in the Eastern Interconnection to look at more of a comprehensive solution to the loop flow problems, looking at the allocation and dispatch as well.

Thanks.

CHAIRMAN KELLIHER: Thank you very much.

I'd like to now recognize Mr. Lloyd Yates, Senior Vice President Energy Delivery with Progress Energy Carolinas.

MR. YATES: Thank you, Ed.

I'd first like to thank the Commission for inviting me to speak to this panel on transmission and operational issues. This morning we spent most of the time talking about the benefits of being a border utility. But I also think it's important to understand here there are also some disadvantages to being a border utility.

Progress Energy, we're a vertically integrated utility headquartered in Raleigh, North Carolina. We did become a border utility recently by AEP joining PJM in 2003, and then Dominion subsequently joining in 2005.

The main negative impact that's had on our company is a dramatic increase in unscheduled loop flows across our system. We realize that other companies also experience loop flows. This is not unique to Progress Energy. But I think we've seen a lot more than our fair share. Let me give you some examples.

In 2003 before AEP joined PJM the peak loop flow we experienced across our system was 500 megawatts. In 2005 after AEP joined PJM we saw peak loop flows of 800 megawatts. PJM, the flows across our system peaked at 1500 megawatts, which is three times what they were prior to AEP joining.

Even worse, this year in February 2007 we saw a peak of 2700 megawatts of unscheduled loop flow. 2700 of those megawatts were being used up with unscheduled loop flows. That's 75 percent of our import capability being used as unscheduled loop flows.

Just so you know, this is not an isolated occurrence. Throughout January and February of '07 we saw loop flows averaging between 1500 and 2700 megawatts every day. We realized if we don't do something about this, this has the potential to jeopardize both reliability and operations of our system. We think it's a problem. Clearly it's a problem. And we are working to address it.

We've currently worked with PJM via a joint operating agreement. That would establish when Dominion joined PJM through some of the operating committees. And progress has been very slow. But we are optimistic that we're going to come to some solution.

Also we expect to approach some other parties who have had some unscheduled loop flow impacts on our system. And we'll be approaching these parties in the near future, although we have no official way to get those parties to the table.

At this time what we're not asking here is for FERC to get involved at this point. I think we're going to continue to try to work through this. But what I wanted you to see is that this was a problem. I'm sure you can understand that we can't continue to absorb these kinds of unscheduled loop flows without some level of relief or compensation.

I want to thank you for giving me the opportunity to speak as a member of this Panel.

CHAIRMAN KELLIHER: Thank you, Mr. Yates.

I'd like to now recognize Mr. Paul Malone, Regulatory, Planning and Contracts Manager with Nebraska Public Power District, representing the Mid-Continent Systems Group.

Welcome.

MR. MALONE: Thank you.

Good afternoon. I appreciate the opportunity to participate in this technical conference on behalf of the Mid-Continent Systems Group. MCSG is a group of thirteen transmission-owning utilities who are members of the Mid-Continent Area Power Pool, or MAPP. Our participants' systems represent over 19,000 miles of transmission lines. Our systems are interconnection with PJM, SPP, Midwest ISO, and other non-RTO utilities.

Three main points I would like to emphasize today are that non-RTO systems contribute fully to fund and implement reliability services; number two, congestion and seams issues are continuing concerns that should be resolved through negotiation between neighboring systems or the NERC committee processes; the third, recent proposals to revise the RTO to non-RTO congestion management process or CMP must not adversely affect reliability.

To the first point, that we pay all of our full costs, we receive and pay for NERC reliability coordination and tariff administration services under a transmission services agreement that has been in effect since 2001 between MAPPCOR, a contractor for MAPP, and the Midwest ISO. MCSG participants pay four million dollars per year for the reliability coordination service alone.

To that point a lot of the data points that we talked about that the Midwest ISO has comes from MAPP member systems. When the transmission service agreement terminates in February of 2008 we intend to negotiate a new agreement so the Midwest ISO continues on as the reliability coordinator for our participant systems.

Further, we pay all required tariff service from adjacent RTOs when our merchant function personnel conduct transmission transactions under their RTO tariffs.

In addition, our transmission operators follow all directives issued by the Midwest ISO as the reliability coordinator, including redispatching generators during TLRs and other emergency events. The Midwest ISO members who are participants do not receive any compensation for this emergency redispatch, even though we're in the same reliability coordinator footprint.

The second point, seams issues and transmission congestion are going to continue. We should resolve those through negotiations or the NERC standards process.

Our region presents some unique challenges to the seams agreement due to its long history of development of transmission and generation. In 2002 approximately half the members left MAPP and joined the Midwest ISO. We recognize this creates seams issues from the parallel flows. So we entered into a seams operating agreement with the Midwest ISO prior to the start of the Midwest ISO LMP market in order to assure that these parallel flows were properly accounted for and managed.

We've actively participated in a seams team and a seams implementation working group on a regular basis to resolve all these technical issues. However, there are some technical issues which parties have been unable to resolve. As a result on January 30th the Midwest ISO provided a notice of termination of the seams operating agreement, effective January 31st, 2008. MCSG participants are committed to working with the Midwest ISO to renegotiate the SOA and understand that the Midwest ISO shares this commitment, based on statements in their letter of termination.

MCSG participants believe that many of the unresolved issues relate to the Congestion Management Process, the related NERC TLR standards and waivers granted to the RTOs, and the NERC interchange distribution calculator, or IDC. As such, if we are unable to resolve the issues through renegotiation of the seams operating agreement, since the NERC standard is applicable to the entire eastern interconnect, any changes to the standard should receive input from a broader audience than just those parties to the seams agreement. If we were to upload more current generation to seams information all the parties in the eastern interconnect should do likewise.

My third point, reliability must not be adversely impacted or affected by changes to the CMP.

MCSG participants are concerned about an increase in the number of TLR events, particularly TLR 5B events -- that's full curtailment -- since the start of the Midwest ISO LMP market. There have been 38 TLR 5B events in the two years since the Midwest ISO started this market whereas there were only 26 TLR 5B events in the three years prior to the commencement of the Midwest ISO LMP market. Even with the CMP procedures, TLR 5 activity has increased sharply. It's our belief that the increase in TLR 5 events is a sign of degraded reliability.

It's widely recognized that TLR is not as effective or fast as redispatching generation to resolve congestion. However, during these TLR 5 events the MCSG participants redispatch generation, just as the RTOs do. The main concern is that systems operators should work to minimize serious reliability issues embodied in the number of TLR 5 events.

Changes currently being discussed to revise the NERC TLR standard, associated waivers for the RTOs, and the IDC must be shown to not result in an increase in TLR 5 events.

Bilateral markets like that operated by MAPP are bound by the TLR standard. It does not provide any alternative for redispatch prior to firm curtailments by systems operating in bilateral markets. Instead the IDC identifies all non-firm tagged transactions to be curtailed first.

In sum, the MCSG participants believe that they pay all of the appropriate reliability costs related to their operations as a border to several RTOs. We are committed to working with the Midwest ISO to renegotiate our seams operating agreement and to work with the RTOs to address and resolve these issues. We believe it will be absolutely necessary for NERC and the other non-RTO entities in the Eastern interconnection to engage in resolution of the issues as changes to the TLR standard, waivers and IDC are contemplated.

Again, I'd like to thank you for the opportunity to talk today.

CHAIRMAN KELLIHER: Thank you, Mr. Malone.

I'd like to recognize JoAnn Thompson, Policy and

Compliance Advisory at Otter Tail Power Company.

MS. THOMPSON: I represent Otter Tail Power Company. We're a vertically-integrated transmission owner of the Midwest ISO and a balancing authority area operator. The Otter Tail service territory is quite large, about the size of the State of Wisconsin. However, it's very rural and has low load density. In fact, the average size community that Otter Tail serves is about 300 people.

Otter Tail has firsthand experience with the market to non-market seam considering that about half of the Otter Tail BA is MISO and half is non-MISO, and only 30 percent of the BA load is Otter Tail's. Today I will describe three areas to which Otter Tail believes attention should be given: generation interconnection disparities, transmission related inequities, inefficiencies around the dispatch of generator units and congestion management.

If you look at a map of the western edge of the Midwest ISO you notice it resembles a Holstein cow. This spotted pattern reflects the intermingled nature of MISO and non-MISO entities. Due to this intermingled nature it's not clear whose system the generator is interconnecting to.

We have encountered questions such as whose interconnection process must a generator follow; who provides the transmission services; who receives the transmission revenues or credits the network upgrades; how does MISO's cost allocation apply to facilities that are in part non-MISO and part MISO; are there better market opportunities, less requirements or less cost with one process over the other?

We have encountered a situation where the physical interconnection is to MISO; however the flows impact the non-MISO system such that basically the interconnection is with their system.  A converse situation is one where a generator is located near a good fuel resource that's near the non-MISO system; however in order to directly benefit from the MISO market and avoid a rate pancake it's proposing a transmission line that's more than 100 miles long to directly tie into the MISO system.

Another layer of complexity is the duplicity between the MAPP and MISO process.  We can go through the MISO process, yet we still have an additional layer of accreditation and deliverability within the MAPP rules. What should be a simple and straightforward process becomes complicated, inequitable, costly, and requires more time by all of the parties involved.  Policies should be developed that will facilitate a vibrant market, provide an incentive for generators to interconnect to the market, yet not cause undue harm on the transmission owners or balancing authorities.

Shifting now to transmission projects, the question being asked is whether the rules in place distort investment on the scene, adversely affect obligations or impact proper cost causation.

Presently there isn't a method to allocate new project costs across the western seam. Projects identified in Midwest ISO's transmission expansion plan may directly benefit the non-MISO transmission owners. But those entities won't bear any cost obligations.

Some other cross-border questions of concerns are the joint ownership structure, can it be divided or undivided; how transmission rates and revenues are allocated and how a jointly owned line can be partly MISO, part non-MISO.

Given the recent termination of the MAPP-MISO seams operating agreement the parties need to come together to develop cross-border solutions. However, if MAPP and MISO produce an extraordinarily effective seams operating agreement, unless all of the MAPP member companies individually execute that agreement it will have no bearing on those entities. So the seams concerns will not be resolved all of them signing that agreement.

Otter Tail has joint-owned units that consist of MISO, non-MISO entities. Prior to the centralized dispatch each owner would receive its commensurate pro rata adjustment. All owners were on a level playing field.

Now that we are in an energy market with centralized dispatch the MISO portion is under that centralized dispatch function and the non-MISO portion of the JOU is not redispatch. Any redispatch that is needed only occurs on the MISO share. In fact there are some instances where the non-MISO JOU portion receives their full entitlement and the MISO owners don't receive any of their redispatch, so they actually have to purchase from the market. An equitable solution needs to assure that all shares will be commensurately adjusted.

There are opportunities to improve congestion management and provide the non-MISO generator-owners with opportunities.

In the western region there is not always enough MISO generation that can be consistently controlled to relieve the congestion. When LMP prices become negative MISO could implement a mechanism to provide an incentive for the non-MISO generation in the Dakotas to help alleviate the constraint. By lowering their generation the MAPP members in MISO could develop a redispatch mechanism for relief similar to the MISO and PJM real-time congestion management. Not only would this allow more MAPP energy to flow but also market efficiencies could be gained.

Otter Tail suggests that best practices across the seams should be looked at that have already been established and proven. They could apply to several areas on our western seam, such as reciprocally coordinated flow gates for the North Dakota export flow gate and applying the three percent threshold for market flows, as recently approved for field trial by NERC.

As MAPP and MISO begin to engage in negotiating the new seams operating agreement Otter Tail encourages the Commission to direct these entities to develop solutions that are comparable to other seams within the Eastern interconnection. Otter Tail advocates an unbiased solution that offers clearly defined and equitable processes, inhibits barriers, and does not give a certain set of parties on either side of the seam preferential treatment or benefits to the detriment of those on the other side.

In all practicality an applicant should be able to flip a coin -- heads being in the market, tails being out -- and it shouldn't matter where that coin lands, whether heads or tails, if the solutions are equitable.

Thank you for your time.

CHAIRMAN KELLIHER: Thank you very much.

I'd like to now recognize Gregory Pakela, Manager of Transmission Market Development, DTE Energy Trading.

MR. PAKELA: Thank you, Commissioners. I want to thank you for this opportunity to participate in this technical conference on behalf of DTE Energy Trading.

DTE Energy Trading, a subsidiary of DTE Energy, is a physical gas and power marketing company located in Ann Arbor, Michigan. DTE has substantial experience in managing transmission positions throughout the eastern interconnect, including the organized RTO market, the Canadian IESO, and bilateral day-one markets such as the SERC region.

DTE would like to present a case study based on its operating experience in the LG&E control area. This case study is a real world illustration of the consequences that can arise when a vertically-integrated utility is permitted to leave an RTO in order to return to a day-one bilateral market.

In the case of LG&E transmission customers now find themselves in a pre-Order 888 world due to lack of ATC to destination markets outside of the LG&E control area.

DTE has a unique perspective because we have been active participants throughout the period that spanned LG&E's participation under the MISO day one entity to operations and the months subsequent to LG&E's exit from MISO on September 1st, 2006.

I will conclude my remarks by presenting what we consider to be the next steps in resolving the competitive issues that have arisen since LG&E's exit from MISO.

DTE was a participant in a three-way arrangement under which it purchased power from a group of municipal customers located in Kentucky known as the KU municipals at Kentucky Utility's generation bus. DTE scheduled this power up to a week in advance and procured day ahead point to point transmission in order to flow the power out of the LG&E control area to destination markets, including MISO, PJM and TVA. This arrangement worked smoothly under both MISO's day one and day two markets. However, LG&E's exit from MISO has been an unmitigated disaster from the perspective of customers like DTE seeking to arrange firm point to point transmission through the LG&E control area.

Beginning on the very first day of LG&E's exit from MISO on September 1st, 2006, DTE consistently found itself unable to procure on an advance basis point to point transmission from the LG&E control area to any of the destination markets. As a result LG&E's exist from MISO virtually destroyed the value of DTE's contractual arrangement with the KU municipals.

DTE contacted SPP, the independent transmission operator for LG&E, to inquire about the lack of firm transmission. The ITO explained that there was no ATC on any of the paths that DTE successfully used prior to September 1st, 2006. This averse impact occurred despite the fact that, one, the ITO cited no operational changes for the lack of ATC, and, two, DTE made its request in what is decidedly an off-peak season as far as the amount of load on the transmission system. In effect, this left the power stranded at the KU generation bus.

DTE marketing personnel sought alternative arrangements with the LG&E marketing arm to substitute hourly non-firm transmission in place of day ahead transmission since ATC was often available on an intra-day basis. LG&E repeatedly refused our request to make intra-day changes in our energy schedules, which was particularly disturbing given the fact that LG&E had apparently accommodated its own intra-day energy schedule changes to take advantage of hourly non-firm transmission.

Ultimately the KU municipals suffered as well because the RFP that they put out went unsubscribed for 2007, and they ended up selling the power to LG&E. Thus the KU municipals were denied the opportunity to take advantage of the competitive marketplace and are now the equivalent of pre-Order 888 captive customers.

DTE and the KU municipals did not simply stand pat. We had a meeting with the SPP ITO staff in January at SPP's headquarters in Little Rock. There were several possible solutions that came out of our meeting that SPP agreed to pursue:

One, study the reasons for the lack of ATC due to constrained flow gates and critical values that are incorporated into the ATC calculation.

Two, submit the issue of off-path usage on constrained flow gates through the inter-regional congestion management committee, a seams coordination group made up of regional transmission providers including MISO, PJM, and TVA.

Three, develop a non-firm ATC calculation for advanced sales of non-firm transmission. This non-firm ATC calculation methodology would be less conservative than that used for calculating firm ATC. Non-firm ATC would include capacity that would otherwise be absorbed by capacity benefit margins, which is released under normal circumstances prior to the day of flow for sales of non-firm transmission.

Finally, seek contractual flexibility that would enable a marketer to use intra-day hourly non-firm transmission.

Unfortunately there is no timeline or guarantee that our efforts will bear fruit.

DTE would also like the Commission to consider the impact of mergers and prior merger order conditions between utilities that operate in bilateral markets and to take affirmative action when competition has been or could be harmed. The Commission itself stated in the LG&E and KU merger order that if LG&E and KU sought permission to withdraw from the Midwest ISO that -- quote:

"We will evaluate that request in light of its impact on competition in the KU designation markets, use our authority under Section 203(B) of the Federal Power Act to address any concerns, and order further procedures as appropriate."

Our experience is in stark contrast to the testimony of LG&E's expert witness, William Hieronymus in the LG&E MISO exit proceeding when he concluded upon his review that there would be -- quote: "No significant adverse competitive impacts."

In closing, DTE asks that the Commission enforce the conditions that accompanied its approval of the LG&E-KU merger and the company's withdrawal from MISO. To paraphrase the late Senator Lloyd Bentsen, DTE Energy Energy Trading knows day one markets, and, Commissioners, this is no day one market.

CHAIRMAN KELLIHER: Thank you very much.

Let me ask a question just about LG&E's withdrawal. The logic of your position seems to be that we should not have allowed the withdrawal because we should not allow withdrawals. Is that your position? Or is it that we should have allowed the withdrawal but there are other actions we should have taken subsequent to withdrawal?

MR. PAKELA: It would not be my position that you should not have allowed the withdrawal as a matter of course. But as time goes on and you see what the impacts are, it would be my position that they need to mitigate the lack of a competitive market in their service territory, in their control area.

CHAIRMAN KELLIHER: On what basis? Let's assume they'd actually never been in MISO in the first place and you have the exact same situation that continues today. Are you saying we should act in that second scenario as well, forgetting the fact that they were?

MR. PAKELA: Yes. There was a merger order that had conditions associated with ensuring that competition existed within that control area. That merger order was that LG&E and Kentucky Utilities join an RTO and that RTO basically started out as a MISO day one market.

Now that they've left their contention was that things would return back to the era that existed under the day one situation. But we found that not to be the case, that there isn't any transmission any longer.

CHAIRMAN KELLIHER: I should have divvied up the time when I started. We have 55 minutes. Let's say Staff is a commissioner; you're all equal to a commissioner.

(Laughter.)

CHAIRMAN KELLIHER: Let's divide it up four ways. My math fails me. Twelve minutes apiece. And you can take two minutes off mine and I think it will all work out.

I'm not a man of science. I struggle with these calculations.

COMMISSIONER SPRITZER: I'm not an electrical engineer so I'm not going to use twelve minutes.

CHAIRMAN KELLIHER: Thank you very much.

I'm now struggling with -- Let's say there's no merger. There's no merger commitment. Again, they were never a MISO member; the same situation is occurring. Do you think we should act?

MR. PAKELA: Let me elaborate with another example.

You have a group of municipalities in the KU service territory. And at one time they would have at least had the ability to shop that power that they had available to them to KU and LG&E. To some extent there would have at least been a modicum of competition. To borrow a phrase that Public Power likes to use, there would have been the equivalent of yardstick competition. You would have had at least two entities side by side that could have potentially competed for that power.

CHAIRMAN KELLIHER: Let me turn to Mr. Kormos.

I have to admit the frustration on TLRs versus LMPs sometimes seems like a religious debate, to be honest.

(Laughter.)

CHAIRMAN KELLIHER: It seems like people believe very strongly in one or the other with almost religious fervor and they view with great disdain the other approach. But they never quite reason their way to explaining to perhaps the doubting Thomas why one is better than the other.

SPP actually had a great example once. They looked at a particular kind of transaction and they pointed out what the effect of a TLR would have been and what the effect of an LMP was.

Is there something like that that you can point to? Your argument I think is that TLRs are inefficient and that they do more than correct?

MR. KORMOS: If you'll allow me, I'm old enough that actually I've been at PJM 19 years. So I was there prior to the LMP data back there in the power pool days of split the savings. And the difference is really that redispatch is not related to an LMP market. Redispatch, security constrained economic dispatch is what we did in the power pool days, and in my belief every utility still does. The difference is that right now what we're trying to do is in order to manage transmission constraints --

CHAIRMAN KELLIHER: I'm sorry, you used to redispatch to avoid a TLR.

MR. KORMOS: Back in the power pool days there were no TLRs. But we would redispatch the most effective generation. That was the power pool concept. When a transmission constraint showed up on your system you would redispatch the most cost effective. You'd look at the effect the generator has. And obviously the closer you are to the constraint the more effect you have, and the price of that generator, and that in the power pool days was cost.

Now the savings back then, we did split the savings. So if we raised one one party's generator and lowered somebody else's, we split the difference between the two. We'd build it out.

But again, the concept was you looked at the most cost effective generator to control that constraint. That is almost always near the constraint. The laws of physics again: The biggest impact is going to be the generator closest there. Under TLRs we've moved away from that concept. Rather than most the most effective, we curtail contract. We do it based on assumptions that are vague and non-transparent. You look at the effect you might get based on the control area aggregation, a proxy for what a control area generation would be, and raising another one.

But as we explained earlier, you don't know what the generator is going to actually raise. And many times they don't know anything; they just cut that contract and they'll just go buy it someplace else and they won't change their generation at all. So as an operator, it's just a bad way to operate the power grid. And we're a pretty important part of the economy on the grid and we should really be looking. Forget LMPs. We fully understand that; we're not here trying to support that.

We have to find ways of being able to redispatch the system more efficiently, more correctly, in my opinion. And they'll compensate each other. We're not suggesting that people should have to redispatch without compensation. We have our way; it's accepted in our area. But others hopefully can come up with theirs as well.

CHAIRMAN KELLIHER: Redispatch without compensation or loop flows without compensation, are they the same thing? Are you complaining about the same thing, that you redispatch without compensation?

I should be more precise, Mr. Malone. I was looking at you. I should have actually made that clear. But you were complaining.

MR. MALONE: I was trying to explain that when the severity of the constraint raises to the level that we cut all the non-firm we can cut and there's still an overload situation, we've got to ratchet it up and curtail firm point to point as well as generation for load on a pro rata basis. And we do that.

But in my opinion when we get to use firm curtailments we've got a reliability problem. We shouldn't be getting there in the first place. I'm not advocating at all that TLR is a better tool. It's a blunt tool; it's not efficient. It's the tool the industry adopted. It's the TLR NERC standard that we are required to abide by.

We had discussions within the MAPP community about considering developing a redispatch proposal in lieu of TLRs. We just started that discussion. I think we'll look at it because we've just had too many TLRs.

But I want to point out in the MAPP region we've always used a flow-based analysis. We're not using contract path; haven't for years. We don't approve transmission unless we've looked at the flow-based analysis of that request that it goes through all of our flow gates and all of our coordinated flow gates with MISO, SPP, and others. That's step one.

You can't avoid and get something approved that doesn't have capacity on the flow gates. Until we get a redispatch proposal it would seem to me we would be in violation of the NERC standard if we didn't get those tags when congestion occurs.

CHAIRMAN KELLIHER: Mr. Yates, what's the difference between you and Mr. Kormos in your lack of compensation? You're both complaining -- I don't mean complaining in the pejorative sense. You're both concerned about loop flows and redispatch -- And I'm struggling a little bit here. I'm not an engineer -- without compensation.

But in your case you have better information about what's happening in PJM and how that's causing loop flows on your system than PJM has certainly outside of PJM.

MR. YATES: I don't think there's a big difference between what we're saying. We're saying these people are essentially using the Progress Energy Carolina's transmission system and we're not being compensated for it. We plan our system collectively with other IOUs in North Carolina and some of the municipalities.

We use unscheduled loop flows, but they're really not a part of our plan. So our import capability gets used up. It causes operational problems and reliability problems. I think we're saying the same thing. Either we need compensation for this or figure out a way to relieve this. Otherwise it's going to cause some other problems.

CHAIRMAN KELLIHER: I just want to ask Mr. Kormos a few questions about PJM in New York. The existing seam between PJM in New York, is that the worst seam PJM currently has?

MR. KORMOS: No, I wouldn't say that. I think right now the issues we're dealing with are on our southern side.

As Mr. Yates has pointed out, we've seen significantly more loop flows on that part of the system. As Andy mentioned, we did a five-month analysis. We had to change some interface mechanisms on our side to try to get at least in balance.

If you read our State of the Market report, we have seen it better. But obviously it's still there. It may be different sources at this point than it was prior to that. We're probably struggling more on our southern side at this point than our northern side.

CHAIRMAN KELLIHER: With New York PJM why wouldn't you have something like what PJM has entered into with MISO?

MR. KORMOS: We have. A while back we had the Dunkirk agreement, the Lake Erie circulation that used to exist still exists. But there was a time of great concern where we could redispatch the Dunkirk units. We would pay for those prior to First Energy being in place. We dispatched their units as well. We also had an agreement with the PS kind of deal to reallocate and move the flow of that onto each other's system, depending on who's constrained and who is not.

We have done some initial things with New York. We are right now sitting down, showing them what we've done with the MISO. And our hope is to get a proposal together and do something with New York as well.

CHAIRMAN KELLIHER: Did it lead you into a similar agreement in the south, or was it complicated by the fact of there being multiple players you need to negotiate with?

MR. KORMOS: My opinion is we could. But we need the transparency of the dispatch. We need the information. We need to be assured that there's fair pricing so that our members have assurance that if we do pay for something that we are in fact getting the service from it.

I think that is the big difference between those to the south and MISO in New York. There is confidence in the market; there's confidence in the transparency of the price signals, and that we can use those to come up with compensation mechanisms.

CHAIRMAN KELLIHER: Are you talking about Progress? Are you talking about North Carolina? Are you talking about all of SERC?

MR. KORMOS: It goes right on down the line.

CHAIRMAN KELLIHER: To the ocean, to the water. Okay. Thank you very much.

I don't have any other questions.

Commissioner Moeller.

COMMISSIONER MOELLER: I just wanted to get Mr. Yates' response or discussion in the sense that you did outline your problem and the increasing nature of it, unless

I heard it other than the general area of being compensated, if you have solutions that you are recommending.

MR. YATES: I think there are physical solutions to this problem, too. We were probably lucky to implement being kind of the last-calls. There are other ways to prevent this problem.

Again, this problem also -- it's not just PJM causing this, but there are other utilities who sell power into PJM that come through the PEC system. It's kind of our attempt to approach those parties to work with that. It's been a little bit of a dilemma. We haven't been bringing it to the table. So they're using our system when you sell power.

COMMISSIONER MOELLER: I'll have some more questions as we move along.

CHAIRMAN KELLIHER: Commissioner Spitzer.

COMMISSIONER SPITZER: If I may follow up, the same issue occurred to me. When Mr. Kormos and Mr. Yates, representing different segments, have similar issues.

Mr. Kormos, if I can simplify, entities are taking advantage of the market in PJM. And as a consequence there are these unscheduled loop flows.

MR. KORMOS: Yes.

COMMISSIONER SPITZER: Mr. Yates, I was wondering why you haven't scheduled loop flows which were taking place. It's not a matter of -- it's your market, obviously. In some circumstances you say that your transmission system is being used to access the PJM market and the unscheduled loop flow on your transmission system was of consequence, is that right?

MR. YATES: Right.

COMMISSIONER SPITZER: Is there also a circumstance of entities within PJM selling into your service territory and creating the same unscheduled loop flows?

MR. YATES: That probably is not a significant contributor to the problem.

COMMISSIONER SPITZER: It is the same root cause, to sell into PJM causing use of transmission in discrete ad hoc transactions.

MR. YATES: Selling into PJM, selling from other entities into PJM causes some of it. Then there's the movement of power within PJM from one part of PJM to the other where the flow goes down and back up into PJM versus across.

COMMISSIONER SPITZER: I'm trying to be artful on how to phrase this. Is there any pattern to these loop flows that suggests an intent to create these unscheduled loop flows, or is it simply a consequence of a whole lot of separate transactions?

MR. YATES: It's probably more the latter. I don't think people are intentional. I think it's the latter. It's the consequence of a whole bunch of transactions that are moving and happen to be going through the progress system because there are transmission constraints in other places and not enough transmission.

We have built transmission. The flows will come through our system. And it essentially comes down to physics.

COMMISSIONER SPITZER: In some respects it's a consequence of the fact that you may have a more robust transmission grid as opposed to another entity.

MR. YATES: Yes.

COMMISSIONER SPITZER: So the free-rider circumstance is not really membership in an RTO per se. But you built the transmission; others haven't. And those who haven't built the transmission are deriving benefits from those who have.

MR. YATES: That's correct.

COMMISSIONER SPITZER: In those circumstances you've got a lot of history with FERC orders for existing transmission.

If there's new transmission various cost allocation mechanisms -- if we isolated the nature of the problem as being insufficient transmission, those with insufficient transmission using transmission that they didn't build, doesn't that suggest a cost allocation solution as opposed to some physical -- if Mr. Kormos talks about how difficult it is to get information after the fact, isn't a better approach before the fact to deal with transmission cost allocation?

MR. YATES: I'm not quite sure of the question you're asking me.

I think that we're working fairly well with PJM. I think we're working toward some solutions. And I think because their recent joint operating agreement is in place I think we'll eventually get there.

I think with some of the other parties that are using our transmission system, I think that the operating agreements are fairly old and don't address some of these issues, and as a result it's been a lot more difficult to get them to the table to try and resolve these. I'm not saying it's impossible, but I think it will be a slow, arduous process.

COMMISSIONER SPITZER: Mr. Ott's testimony this morning -- I believe it was Mr. Ott -- the hypothetical from Louisiana, it appeared to be a very difficult and problematic way of assigning a cost, doing forensic accounting months after the transaction has taken place with regard to a specific transaction there are many thousands of similar transactions that in some cases may net out.

If the root of the problem is either inadequate transmission in one service area, one control area, or transmission being built that should be costs which should be assigned differently, that seems a better way of addressing it, again rather than trying to do an after the fact forensic accounting for some transaction for Louisiana to Pennsylvania.

MR. YATES: Think about a transaction that comes from the south of us that goes through our system and into PJM. Because there's not adequate transmission from that point to PJM bringing that group to the table to try and share costs to build a transmission line for transactions that they make -- I would say transactions that they don't necessarily make every day; they're selling excess power into the market -- it's very challenging to get them to come to the table and share the cost of building transmission for those kinds of transactions, especially in a regular utility arena.

COMMISSIONER SPITZER: But in the south there is -- you don't have an RTO, obviously, but there's a history of operating companies across many states. The states cooperate and allocate costs of the various state operating companies.

MR. YATES: Yes.

COMMISSIONER SPITZER: It has been done.

MR. YATES: Again, I'm saying it will be done. We'll get them there and we'll come to a solution.

COMMISSIONER SPITZER: Ms. Thompson, you made a comment. Tell me if I'm wrong. You said there was a duplicitous result. I assume you meant duplicative.

MS. THOMPSON: Right. There's duplicity in the review process.

COMMISSIONER SPITZER: You mean duplication?

MS. THOMPSON: Right.

Would you like me to explain that a little bit more for you?

COMMISSIONER SPITZER: Please.

MS. THOMPSON: For instance, say a generator has gone through the MISO generator interconnection process and it's to a MISO facility. Let's say it's to Otter Tail's transmission system. Let's say Otter Tail was to accredit that generator as a designated network resource. In that case, since we're still part of the MAPP generation reserve sharing pool, MAPP has another layer of review.

Despite the fact that MISO has already reviewed it, it's still on the system. It can be a designated network resource. It's deliverable as a network resource. There's still another layer in the MAPP design review subcommittee where they review it to accredit it and assure that it's deliverable. We'd just like to see the two processes or the two entities recognize each other's processes.

COMMISSIONER SPITZER: So it's only done once.

MS. THOMPSON: Exactly.

CHAIRMAN KELLIHER: Thank you. I now turn to Staff.

MR. KELLY: Ms. Thompson, your remarks were interesting. There seems to be a theme that ran through them that said if you're a transmission customer you're better off being in an RTO, and if you're a transmission owner you're worse off being in an RTO. You went through several examples.

If you're a generator that's interconnecting you're much better off going out of your way to interconnect to MISO than a nearby non-MISO system. If you're in MISO and you're involved in transmission planning, MISO plans benefit those outside MISO but not vice versa. If you're a jointly owned unit the non-MISO member is better off. And you concluded by saying that in an ideal world it really ought to be kind of neutral. You could be in an RTO, not in an RTO, but you bear the same costs.

I couldn't see how you get there. If transmission owners can voluntarily enter and exit RTOs and the owners are better off being outside the RTOs, how do you get there? Is there a way that costs could be imposed appropriately across RTO and non-RTO transmission members in an equitable way?

MS. THOMPSON: That's exactly what we're striving to seek. We're extremely integrated out in our neck of the woods.

You know, in Commissioner Spitzer's opening remarks when he mentioned that he's a history buff, that resonated very much with me because we have a historic relationship with working together. We've got IOUs, we've got co-ops, we've got munis and we've got these joint use systems. We have had a history of working together.

It's interesting now that part of us are in the market and part of us are centralized dispatch. Some of our neighboring intermingled systems are like, well, why can't we just do things like we've done for the last 50 years. It's difficult now, you know, when some are still trying to operate in a non-market regime and some of us have moved forward into this market.

We're neighbors. We're always going to be neighbors. We're always going to be interconnected, intermingled. We have some situations where we own this segment of line, they own this segment of line, we own this segment of line, they own this segment of line, you know, so we've got a historic history of working together.

We just would like, now that MAPP and MISO are going to be renegotiating the seams agreements, we believe there's opportunities for both sides where efficiencies can be gained and where no one party is getting a better heads or tails flip of the coin.

MR. KELLY: Mr. Pakela, in your case study with LG&E were you able to determine if there was less transmission available for firm after an exit from MISO because -- were you able to determine the reason for it? One reason could be an unwillingness to provide; another reason could be that a kind of MISO -- the kind of redispatch that's inherent in LMP might actually free up more capacity so that you just wouldn't have as much if you were to exit.

Did you determine in your talks with SPP as to whether it was any of those reasons?

MR. PAKELA: Yes.

First of all, I'd like to rule out any nefarious activity on the part of anyone. I'm not suggesting that, nor do I want to.

Yes, we did get some fairly specific reasons why there's a lack of ATC. In particular, there are three flow gates -- one of which actually is physically within the LG&E service territory -- that are apparently being loaded up due to off-system transactions. The examples I think that they utilized were transmission sales either originating in MISO or PJM. I believe these would be point to point transmission sales.

What was even suggested to us was that even if you went to the extent of requesting a system impact study and a facilities study and actually bolstering that particular flow gate, you could find yourself in a position whereby the transmission could actually be sold off-path -- and I referred to that; that's the same thing as basically loop flow -- such that if a party purchased an off-path transmission piece that had the loop flow impact on those flow gates and they had rollover rights, you wouldn't even necessarily have access to the improvements and the facilities that you made.

That once more goes back exactly to what Mr. Kormos was referring to when he was discussing this loop flow issue. It also kind of reflects what was going on with the burrowed chambers that Mr. Ott spoke of earlier. You get these off-path transactions that affect flow gates. I don't know if there are any conventions out there that would help you deal with that.

In essence what you have is the potential to want to sell transmission to LG&E to sink into MISO but because of the off-path transactions that flow gate is being already filled up. I don't know what mechanism you would utilize to prevent that from happening. Maybe these joint operating agreements could be revisited or something to that effect.

I guess in response to the other part of your question, yes, certainly the redispatch element was effective. In fact, you know, we had access to this power at the KU bus. We were able to flow that power into MISO throughout the summer months when you would expect there to be some amount of congestion that might even make that transaction uneconomical. But in fact it was economical for us. I would say the day two markets were definitely effective in that regard.

As far as the original day one market, all that I can say is that we operated under the day one market in MISO for this contract for about three months. In the wintertime there wasn't a lot of ATC available. But they permitted us to use hourly non-firm at that time. They were amenable to that and we were able to acquire firm ATC from time to time as well.

Once more, that's not a very good sample set. In the middle of the winter you would expect that flow gates might be utilized more because of the heating season. What we're talking about here, September, October, has got to be among the lowest loading months of the year I would think.

MR. KELLY: Thank you.

Udi.

MR. HELMAN: Mr. Malone, you noted that you've had a large increase in TLR 5B events. You also noted that you use on your side of the seam load-based transmission allocation. So it's not a contract path problem on your side.

On the other side you have an agreement with MISO with reciprocal flow gate management. I guess I was wondering why there is this increase in TLR 5s and whether from your point of view it's more due to the MISO side of the seam or to your side of the seam.

MR. MALONE: Good question.

Those TLR events are MISO-wide. All those events didn't occur in the western part.

I don't have that breakdown. We used flow-based analysis or transmission-based service request approval process. So hopefully we're not oversubscribing the system which we get into in the contract path basis.

Nevertheless we're seeing more TLR events, meaning that the system is being loaded. Why is it being loaded? A great question. Are we oversubscribing it?

In general we recognize that transmission capacity is a pretty scarce mechanism out there. There's not as much around as what would satisfy all of the transactions that want to take place. To me we'd get into smaller and smaller situations. And we're calling TLR 3s;

they continue to ramp up; we go to level four and then level five.

I don't have an answer for you.

Obviously if we were oversubscribing it in the first place we're going to create that situation. That's the best I can respond to that.

MR. HELMAN: These are TLR 5s that you're calling or that MISO is calling?

MR. MALONE: The reliability coordinator calls TLR events.

MR. HELMAN: And your coordinator?

MR. MALONE: MISO is the reliability coordinator for the MISO tariff member as well as for the MAPP region. They provide that reliability coordination. So we're out of the same power office. They have all the data of our generation online, offline, a transmission operator, a control area operator will recognize the loading and they'll notify the reliability coordinator.

But the reliability coordinator calls a TLR event, gets all the data out of the IDC to determine which schedule should be cut on the MISO side rather than cut schedules, which they don't have under an LMP market. Their schedules have gone away; they've disappeared. They went to an LMP market. Schedules that previously went between control areas are gone. So they redispatch, whereas we still have point to point schedules that are being used. Those all have a priority in that IDC.

I would also comment that the IDC has been around for a number of years. I don't think it's really been updated too much other than the changes that are required to start up the LMP markets. The LMP tool set needs to be looked at harder, to be revised.

We do have our seasonal load models in there. That's what's required. We provide it. We also have the point to point tags in there. Could it be changed so that more real time loading information could be provided? Yes, it could, the market's upload or market flow calculation. It's just a calculation; it's not a real-time flow. But it's certainly much more accurate than seasonal models would be of what the actual use of the system is. So there are some things we need to update.

The eastern interconnect uses TLRs as a standard for everyone, and yet maybe half of the load in the interconnection has got a waiver to a standard. It seems like there was something missing here. Something needs to be changed or revised.

CHAIRMAN KELLIHER: Commissioner Moeller has a question.

COMMISSIONER MOELLER: Ms. Thompson, thank you for your testimony as well.

You mentioned the three percent threshold in contrast to the five percent. It's probably a question for NERC because they approved it for the field trial. But can you elaborate a little bit more on that decision? You obviously talked about the conflict that exists between the zero percent and three percent really is what we're talking about.

MS. THOMPSON: This is somewhat outside of my expertise. I know just enough that I can try to answer your question on that.

As you're aware, TLR is handled on a control area to control area basis. We actually have -- The Otter Tail balancing authority is considered a market VA and we actually have non-market load in our control area. So they aren't TLR'd because our VA is redispatched under the MISO process.

On the other flow gates it's my understanding, not only with MISO under this NERC trial, three percent is working and the MAPP members still want the market redispatch to be down to zero percent whereas NERC is at five percent. What we're suggesting is perhaps let's try this three percent and see how that works.

COMMISSIONER MOELLER: Thank you.

MR. KELLY: I have one more.

CHAIRMAN KELLIHER: Sure, Kevin.

MR. KELLY: Mr. Kormos, you were going to talk about loop flow and dispatch and planning. I was wondering if the Order 890-required planning process might be a forum for addressing some of these issues.

Instead of thinking of planning as simply building more power lines, if planning could take place collaboratively between an RTO and its neighbors in such a way as to put in place procedures, processes, agreements, real-time granular data exchange, whatever, in order to say you don't need a line and we wouldn't need as many TLRs if we coordinate it in this way.

It's really a two-part question. One, what more could be done between RTOs and the owners. And is the Order 890 original planning process appropriate, or should that be worked out through NERC, as Mr. Malone said, through some other agreement process?

MR. KORMOS: I think in some cases one of the first things we need to do, as I see, is agree on sort of the allocation methodology.

Well organized loop flows exist. We have to agree as to what is the allowable level that you're going to tolerate on your system before you ask for relief or compensation. I can tell you, I'm very close friends with many of the MISO people now because we sat in very small conference rooms for months hashing this out between ourselves, and ultimately coming to an agreement as to how we can do that.

We need to do that. And whether we do that through our joint operating agreements, as Lloyd said, we're already working with them to work out what the methodology is. I think we're getting agreement as to at least historically what our impact on each other has been and what we should accept, and then going forward, which is what the planning process is. As we all add new resources to accommodate how again they will impact each other and how to make sure it's being done fairly, whether it's through compensation or building transmission jointly or recognizing that the flows exist in real time.

I didn't talk about planning because I'm encouraged by the order. And my hope is that the planning process will become much more open so that we can see what the plans are and we can work with each other to look at how we're all going to accommodate the load growth that is going to exist, the new resources that are going to be built, and to be assured. And again, are we simply going to be relying on contract paths and just accepting and having to deal with the flow after the fact?

MR. KELLY: If you were doing your planning process and Mr. Yates was doing his separate, that wouldn't be as good as if you were somehow doing it together, isn't that right?

MR. KORMOS: Yes. I think we need to be doing it better. We need to be looking at -- again, we know we put flows on his system and he can tell you every five minutes what they are. Vice versa: He puts on flows. We need to be coordinating that and make sure as we go through the planning process that the system can accommodate it.

I think the problem, as Mr. Yates pointed out, is -- I think this is what Andy alluded to -- when flows show up we can't easily tell you where they're coming from. We can look, and we know too much is coming in from Progress than is scheduled and we know not enough is coming from someplace else. Andy spent five months trying to go all the way back to where that energy was actually being produced at. That ultimately was driving how it was flowing: where it was being produced at, where was it being consumed at; who was over-generating.

When you start looking at the contract path you lose all that detail unless you have to go back and do the forensics and try to piece together who is actually generating more and who is actually generating less. That's the flows that resulted from that.

CHAIRMAN KELLIHER: Any other questions?

(No response.)

CHAIRMAN KELLIHER: Why don't we take a break here. Let's resume at three o'clock rather than 3:10.

I want to thank the panel very much for their help today.

(Recess.)

CHAIRMAN KELLIHER: If we can resume the technical conference. If we can close the doors. If people engaged in conversations can either end their conversations or go out in the hallway. The panelists are here. That's excellent.

I'd like to now recognize Rana Mukerji, Vice President Market Structures, New York ISO.

Welcome.

MR. MUKERJI: Good afternoon.

I wish to thank the Commission for the opportunity to discuss Northeast ISO RTO seams initiatives. I will provide a brief background, highlight the accomplishments to date, and address the ongoing effort towards the resolutions of seams issues.

We need to address the inter-regional coordination of seams issues. It's not just a recent phenomenon in the northeast. Before restructuring of the wholesale markets, for over 25 years the northeastern power pools, which was the New York power pool with the PJM and NEPOOL, provided regional coordination of operations and economic power interchanges. Seams issues were recognized and various mechanisms evolved to address such issues.

One of the first benefits of restructuring in the formation of wholesale electricity markets in the three former power pools was greater transparency through locational-based marginal clearing prices, or CMP. This led to greater impetus in resolving seams issues between the ISO RTOs of the northeast. And currently Ontario IESO has joined these efforts along with the New York ISO, PJM, and New England ISO.

Seams issues arise as differences in operations, market design, and planning exist among neighboring systems. To address these issues adjacent markets must actively create coordinating mechanisms to bridge these differences. The northeastern ISO RTOs have established numerous regional coordination agreements between themselves, as well as adjacent control areas.

I have a handout which lists some of these agreements. Operational differences are primarily addressed through coordination of scheduling, congestion management, and management of loop flows. There are differences in market designs among the different ISO RTOs. These necessitate special products for transmission congestion contracts, firm capacity rights, and other market mechanisms between adjacent markets.

In the planning arena coordinated system planning produces region-wide benefits by establishing mechanisms that encourage market participation by a broad range of transmission generation and demand-side response resources. Since the year 2000 the northeastern ISO RTOs, with the cooperation of IESO, have conducted a formal process which includes regional stakeholder participation for the identification and resolution of seams issues. Upgrades are posted on a quarterly basis and stakeholders are provided with an opportunity to participate in the update process through regional meetings and conference calls.

Each quarter the FERC seams report is posted by the ISOs and noticed by the Commission to document progress on these coordination efforts among the eastern ISO RTOs. To date the northeastern ISO RTOs have completed 42 seams initiatives or projects which are illustrated in another handout that I have.

Some notable accomplishments include the elimination of rate pancaking between New York ISO and ISO New England; the expansion of New York ISO; ISO New England reserve sharing program to the NPCC region; interconnection and emergency and transfer agreement among all northeast ISOs and RTOs with the neighboring control areas; and the northeast ISO RTO planning coordination protocol executed by PJM, the New York ISO, ISO New England, with the participation by IESO, Hydro Quebec, New Brunswick, and support from MPCC.

In addition some major market advances through ISO New England's SMD 1, New York ISO's SMD 2, and the PJM expansion have produced advanced scheduling and coordination system. Some of the projects we have underway at the New York ISO to address differences among our control areas and the adjacent ISO RTOs include the establishment of the new pricing mechanism with PJM to promote more efficient interchange of energy, open access for the scheduling of control level tie lines with New York, such as the new Neptune project with PJM, and the 1385 timeline with ISO New England.

We are in the process of establishing a congestion management protocol with PJM and we expect to present a strawman proposal to our market participants this fall. And we are coordinating regional resource adequacy and regional planning.

I have another attachment which shows the timeline for the open seams projects which are underway.

The New York ISO's perspective is that while a significant portion of the seams issues have been addressed in startup, the remaining issues seem to be the tougher issues. Specially the next series of solutions of seams issues between the ISO markets relate to congestion management, loop flows, inter-regional planning, and cross border market products.

I believe the ISO RTOs in the northeast are well positioned to focus on this next set of more complex issues, and the establishment and acceptance and the robustness of advanced market designs and the rules of each ISO through the deployment of ISO New England SMD-1 New York ISO's SMD-2s, and PJM's expansion have created the market environment and infrastructure for the opportunity for resolution of these more complex issues.

It is my firm belief that barriers to trade in electricity products between the ISO-RTO regions have significantly reduced since the inception of restructured markets. The ISO RTOs are committed towards working towards efficiencies and coordinated operation, market design and planning, as we continue to evolve our markets for the benefits of our customers and other stakeholders.

This concludes my presentation. I look forward to answer your questions.

CHAIRMAN KELLIHER: Thank you very much.

I'd like to now recognize Mr. Richard Bolbrock, Vice President for Power Markets, Long Island Power Authority.

Thank you.

MR. BOLBROCK: Thank you for inviting me.

This topic is particularly important for LIPA.

We very soon will become a trading hub with significant business in the three northeast ISOs when the 616 megawatt Neptune cable goes into service in July. That cable I'm pleased to report is almost mechanically complete. It will be mechanically complete before the end of April. Testing is undergoing its way right now. So it looks like we're going to be on schedule for a July first in-service date.

We believe that FERC was correct in recognizing early on that markets need to be of a large size. We undertook action to integrate LIPA into this larger market and what we believed was going to be a seamless larger market first by building the cross-sound cable, the first -- not building it, but seeing it got built -- the first merchant transmission facility in the country. Second, by causing the Neptune cable to be built, we anticipate that we'll try to further integrate those efforts and try to further integrate LIPA into the pre-existing ISOs.

I'm going to touch upon some of the seams, but not all of them, some of the highlights in my submitted testimony and touch upon what are the key ones. There are certainly more than the ones I've listed. But these are some of the focal ones.

The first is the rate pancaking that exists between New York ISO and PJM. While, as Rana mentioned, the pancake rates have been eliminated between ISO New England

and New York, the pancaked transmission rates remain between New York and PJM and there are no active discussions ongoing to eliminate them.

Regarding the sale of operating reserves between regions, energy transactions can be scheduled between external regions. The northeast ISO RTOs are not allowed to sell operating reserves between regions. This would be very desirable. It would be beneficial to customers, particularly, I might add, in New England, where the operations people could tell you that there is generally a shortage of fast-start operating reserve.

Rhode Island, for example, has an excess of fast-start operating reserve; and with their interconnections with the cross sound cable and the soon to be schedulable 1385 cable that runs between the north shore of Long Island and Norwalk, Connecticut, there will be ample pathways to utilize the sharing of operating reserves.

There are no active discussions ongoing to resolve this particular seams issue. There have been long delays in allowing scheduling over the schedule transmission facilities between regions. I think the 1385 is a fine example of that.

This interconnection, which went into service in 1970, served both the residents of Connecticut and Long Island over the years. It was discontinued from scheduling by their ISOs because their scheduling software could not handle what was a regular occurrence prior to their existence. After many years of delay the New York ISO and ISO New England are expected to initiate scheduling over this facility in June of this year.

I think this is a good example. It's taken many, many years to do something that conceptually is very simple. And I think it points out one of the problems in eliminating seams. That is that the software utilized by the ISOs, particularly New York ISO and ISO New England, is exceptionally complex. It does not facilitate changes easily. It takes a long, long time to make changes, even conceptually simple changes. And it is very costly to do so. And when it's done the history has been that there are errors in that software that need to be corrected.

The budgeted costs for ISO New England alone to allow scheduling over the 1385 cable was a shocking, staggering originally $1.25 million. Within the last couple of weeks that estimate has been raised to just under two million dollars.

I don't recall offhand what the cost for New York ISO to do that is. This is a staggering figure. Fundamentally, it's not only to regional planning. To be very blunt about it, the only projects that have occurred between the regions have been merchant projects. And the two merchant projects in particular were those initiated by LIPA. Additional interconnections between areas are not studied to determine if they might be more cost effective than expensive internal upgrades within a region.

I think southwest Connecticut is a perfect example of that. This Commission held two technical sessions in Hartford, Connecticut in which they explored the southwest Connecticut situation. The Connecticut Siting Council held many months of hearings. In neither of those forums was the alternative ever considered of somehow utilizing the cross-sound cable and/or the 1385 cable, perhaps with an interconnection to the west from southwest Connecticut and New York, which may have been a more technically elegant solution. It most certainly couldn't have been more costly than the ultimate solution that was agreed upon, the very expensive 345 kV loop with many miles of undergrounding.

It certainly would have had many benefits to both regions in addition to Southwest Connecticut barriers. This is a very important point. The Northeast ISO expended considerable effort to develop common definitions and to explore capacity of markets in order to ensure that ICAP could be traded between regions. We now have gone down independent paths with the ability to seamless sell ICAP between regions, but that was an afterthought at best. Significant new barriers are being erected between the markets as the result of lack of regional coordination.

What are some of the things that might be done? I think there's three fundamental things. First of all, there should be some renewed FERC oversight. The Commission should begin a new effort to document the existing seams, develop milestones for resolution and provide close oversight until each seams issue is eliminated as we heard their quarterly report filings. However, the 1385 line was originally scheduled to have that work done in 2005. Then it became June of '06 with a no later than date of October of '06. Then it became June of '07. The latest word now it's the end of June of '07. This seems to me really not an acceptable way to do business.

Very importantly, FERC should take steps to prevent new seams issues by policy. I would urge the Commission just say no to the creation of new seams. You could see the loads, the circle with the cross and seams in there. One of the reasons being, once these seams are created, it takes a lot of money, a lot of time, a lot of effort to correct the seams and to eliminate the seams. The best approach is to make sure they're prevented in the first place.

The Commission should ask as a primary question whether any market rule that's proposed improves or detracts from the ability to resolve seams issues.

Finally, I would urge the Commission to revisit the geographic scope of markets. The inability to eliminate seams in an effective manner, the inability to prevent new seams in the Northeast are, in part, due to the insufficient geographic size of the ISOS in the Northeast, particularly New York and New England.

As part of the FERC review of existing seams issues, there should be additional consideration of whether each issue can be better resolved by some broader regional approach. Thank you.

CHAIRMAN KELLIHER: Thank you very much.

I'd like to now to recognize Mr. Paul Napoli, Director of Transmission Business Strategy, Public Service Electric and Gas Company. Welcome.

MR. NAPOLI: Thank you, Mr. Chairman. I appreciate the opportunity to appear before the Commission this afternoon to discuss our RTO board issues on behalf of the PSE&G companies. PSE&G facilities located in PJM are interconnected with the New York ISO via six ties to New York City and Rockland County, New York. Further, PSE&G's franchise service territory abuts the PJM NYISO seam and the bulk of PSE&G Power's generating assets are located in northern and central New Jersey in close proximity to this seam.

Because of the geographic location of our assets and load obligations, we're sensitive to the importance of effective coordination between neighboring RTOs. In this regard, the PSE&G companies commend the Commission for recognizing the importance of regional planning in Order 890. We believe, however, that while Eastern RTOs have made strides in addressing certain seams issues, significant improvements are still needed.

Today, I'd like to focus on three issues: the need for interregional cost allocations mechanisms for transmission projects; improvements in regional transmission planning and the need to address increasing levels of multi-regional loop flows.

First, the shortcoming of the current transmission planning construct is the lack of a mechanism to fairly allocate costs for projects that are interregional. As the Commission is aware, a number of long-line transmission projects have been proposed in PJM. Proponents of these projects claim that they would relieve congestion in the Eastern PJM and allow increased imports of power from coal plants resources in the West.

Under the current PJM cost allocation method, it is likely that customers in New Jersey would be assigned a high share of those project costs as proposed recipients, proposed beneficiaries. None of these long-line projects have yet been formally proposed in the PJM transmission planning process and the PSE&G companies wish to stress that projects that do return to formal proposals will need to be justified based on a clear demonstration of their economic or reliability value. But if the proponents claims are accepted at face value, however, it seems reasonable that the benefits to be associated with these projects would also be conferred on customers further to the east in New York and possibly even New England.

The current cost allocation mechanism under the PJM tariff, however, does not include any mechanism for analyzing benefits, let along allocating costs of present seams to New York and New England customers. The lack of a regional cost allocation mechanism may also be affecting the scope of projects being proposed. But all the rationales supporting these projects, should apply with equal or greater force to extension of transmission lines from the western portions of PJM and New York City or Long Island.

None of the projects proposed to date have included this element. The builds into New York as being constructed, as mentioned before, the Neptune and IP project are premised on a business plan of capturing high energy prices in New York City and Long Island, and those project goals to increase reliability or reduce congestion in the New York City region are not likely to be proposed.

Second, the Commission needs to accelerate the development of effective processes for interregional planning in the eastern RTOs, a process for addressing seams issues affecting PJM, NYISO and ISO New England began several years ago and has been successful in several areas. The development of an interregional planning process, however, has lagged. While the interregional stakeholder advisory committee has yielded some improvements in a few areas such as data exchange, most of the groundwork that would be needed to conduct true regional planning has not yet been accomplished. Without the development of a common study process that should include consideration of transmission, generation and demand response solutions on an equal basis. Projects that affect multiple regions can never be properly analyzed.

Third, allocation issues associated with increasing loop flows need to be addressed, as you've heard today. As the use of the transmission grid for transactions has increased, it appears that loop flow issues have increased as well. For example, Allegheny Power has claimed that loop flows has increased constraints on facilities in its system. PJM has addressed this problem through a reliability upgrade in the area. The cost of which are being assigned mainly to the customers of eastern PJM customers, including customers of PSE&G. Mechanisms should be in place to allocate costs associated with loop flows to the companies or customers that are actually causing the loop flows to occur.

The current lack of this mechanism is creating free riders who are engaging in transactions without bearing the full levels of the associated costs. Some arrangements address loop flows already exist. Loop flows between PJM in New York resulted in the construction of the Ramapo phasing regulator in New York just across the border from PSE&G's territory. PSE&G participated in the Ramapo project and helped formulate an agreement that sets for target levels for use of each region's respective systems. If over use occurs, payment obligations arise.

Other regional tariffs along the lines of the Ramapo phase angle regulator contract to track usage of the regional transmission system and allocate charges for such use should be developed. Absent such mechanisms, inefficient transactions by these free riders will continue.

PSE&G companies wish to thank the Commission today for the opportunity to appear and discuss the three important issues of interregional cost allocation, planning and loop flows. Thank you.

CHAIRMAN KELLIHER: Thank you very much.

I recognize David Scarpignato, Manager, Regulatory Affairs, Old Dominion Electric Cooperative.

MR. SCARPIGNATO: Good afternoon, Commission and staff. Old Dominion appreciates the opportunity to speak here today. I'm David Scarpignato, Manager of Regulatory Affairs at Old Dominion Electric Cooperative.

We reside in PJM RTO, so you know our perspective. My remarks are based on new seams issues that arise from increasingly large competitive electricity markets that span multiple RTOs in neighboring systems, which is a good thing. The markets -- seeing the infrastructure is expanding -- what I mean is it's larger competitive electricity markets you need to build transmission infrastructure between what I would call the balkanized transmission service territories to that whole system in general.

The markets are expanding and you need the expanded transmission. We have plans to expand the transmission, but we haven't actually built it yet. Once we've built it, cost allocation becomes more of an issue, which really gets to the thrust of my remarks here, the two main issues I'm looking at. The first who receives or utilizes the increment of transport capability and the second piece is, based on that, who pays for it and how is it paid for?

The plan is based on a paradigm shift in the way the utility industry has operated in the past. We're actually moving to markets. To emphasize the size of this boom, in PJM we're looking at approximately $3 billion of upgrades over the next four years. Some people have heard about before have been over five years. To put that into perspective, PJM put in place approximately $400 million of network upgrades from '99 to date. $400 million compared to $3 billion in new facilities is huge. There's a free rider problem. Any time you build network integrated transmission, which I'm sure we're all aware of, the flows go where flows go.

As Mr. Napoli from PSE&G pointed out, there is no cost allocation mechanism for these new upgrades to external entities in the current PJM process. You build these projects and you do the cost allocation totally internal to the PJM system for these new projects, which creates a huge free rider issue. Anybody can make sure of the transmission for external transactions. The free rider also goes beyond simply border transport capability. A lot of people think, well, it's just the amount that you can transfer from PJM into another RTO that's an issue. Really internal upgrades within the huge PJM region are a big deal, also. Internal upgrades that do not increase TPC still benefit external entities.

They see reduced congestion for external entities to reach our trading hubs. If we build transmission between the western hub and the PJM border, say, with New York that's a long distance. You don't have as much congestion there. These grids are put into place. The external entity, New York, in this case, will not pay for those upgrades. They would experience less congestion because of the transmission that's built. It's simply then simply accessing cheaper generation. It's eliminating congestion.

Transmission benefits to external zones in external regions go beyond who actually uses point-to-point interregional paths. There is a free ridership issue. Access into external regions affects energy capacity costs to zones as a whole and not simply to the point-to-point transmission service purchasers. What we're talking about here is if you can get more cheaper energy or capacity from one region into the second region, in the second region you effectively, if it has markets, you lower the clearing price for the entire region, at least in the long run. So the market theory suggests that all the load in that zone is probably benefitted.

A note that New York ISO has additional plans to meet its affective capacity needs through PJM, which requires PJM transmission upgrades to allow that to occur. That's part of how they plan to meet their capacity needs.

With all that said, you can see I'm getting around to what is a true beneficiary here. Cross-border cost allocation must be based on beneficiary and not regional through and out rates. The regional through and out rates, I guess, could be updated. Even so, you're not really assigning the cost to all those who have benefitted. Interregional cost allocations needed to be reflective of both reliability and economic benefits with transmission viewed as a facilitator of region-wide or interregion-wide benefits.

I think we're moving even further from regional markets into a situation where we're experiencing interregional markets. Everything is evolving, which is a good thing. Questions arise on what to do with the current construct for new facilities. We suggest that you need a new system. That we stop for actual usage, but pay based on benefits and interregional market facilitation. Rotor rates that are based on actual usage are limited in reach and they do not extend to the large group of those who benefit. We need to look at benefits and effects beyond transfer achievability.

For example, non-firm point-to-point is not simply excess transfer capability out of an LMP RTO. One thing, it increases congestion charges within the RTO. Recognition of the benefit of accessing PJM electricity without paying relatively more congestion due to transmission upgrade, enhancements must be made.

In summary, we need cross-border cost allocation for new regional transmission. It should be assigned to external regions rather than to regional point-to-point service users to account for beneficiaries and the role of transmission as facilitator of interregional electricity markets.

I'd like to point out that cross-border cost allocation, based on assignment into external regions works with Andy Ott's implied suggestion to move away from contract path transactions, but moving toward an interregional integrated marketplace. The cost allocation structure should reflect this.

Thank you for your time.

CHAIRMAN KELLIHER: Thank you very much.

I'd now like to recognize Mr. Craig Baker, Senior Vice President of Regular Services with American Electric Power. Thank you.

MR. BAKER: Good afternoon. AEP is pleased to participate in this technical conference and applause FERC in its efforts to address these critical issues. The President has charged the industry and its regulators to bring America's electric grid into the 21th Century and to do it quickly in a manner that helps stabilize regional electric rates for American consumers.

AEP's position in this dialogue is somewhat unique. We are the nation's largest transmission owner with 39,000 of transmission, including 2100 miles of 765. We operate in 11 states with more than 5 million customers and we are members of three RTOs -- PJM, SPP, and ERCOT. So we know a lot about seams and the associated impacts. I think the President's approach to the 21st Century of national electric grid is what we all want, whether reasons of reliability, economics or national security. We simply need the Commission's leadership to get there.

We at AEP are partial to the analogy of the interstate highway system for the transmission grid. When we discussed regional rate design and cost allocations, we lean toward a specific analogy, a very specific approach that works for us and is in front of you. Unfortunately, roadblocks, one of which is a clear picture of cost allocations, continue to slow the progress in transmission expansion. Sometimes it seems like we're on the Oregon

Trail, not the superhighway. Every time we think we're in a position to pick up speed, we encounter boulders along the trail and we're never sure what we'll find on the other side of the next mountain ahead or when Snidely Whiplash will suddenly appear.

The NERC's long-term reliability assessment shows that we clearly need transmission relative to the growth that we are expecting in load. A number of obstacles are preventing the trail from becoming a superhighway that we need to achieve the President's vision. All of them boil down to a dire need for more transmission. A major thing blocking that transmission are cost allocation and rate design issues as has been talked about. That is where the nation needs the guidance and leadership of this Commission.

When these issues are equitably dealt with, other issues will have the opportunity to resolve themselves. Transmission owners will have a roadmap to build and with adequate capacity many of the seams issues you heard about today will cease to exist as major problems.

AEP has service territories in 11 states. Four of them have competition. Seven of them are traditionally regulated. One is on the verge of trying to put the two back in, which is an interesting experience. Regardless of the regulatory framework, the states we serve all want to protect their customers from excessive costs from regional transmission management expansion. We don't think that's unreasonable.

The State of Ohio is a good illustration. According to the census, Ohio was a very large state in that part of the industrialized Midwest, but AEP's transmission grid in Ohio is robust. AEP does not deal with congestion problems because the Ohio Commission approved and provided for rates and permitted us to build a robust transmission system. The customer think they barely have squatter's rights over the grid they helped to build. It is now used for regional transmission for which AEP customers are not compensated, yet we find in a new regional era that some would expect our Ohio customers to help fund transmission infrastructure to alleviate congestion west and east of Ohio.

When I think of some of the cost allocation approaches in MISO, 20 percent of the costs are socialized with 80 percent of the cost charged to the beneficiary. In PJM for the time being beneficiary pays all, and in SPP one-third is socialized and two-thirds is benefit-funded. In all of these Ohioans could end up paying for what other states failed to do a long time ago. Understandably, this troubles them, us and everybody who wants to build transmission.

We also must recognize that socializing only a part, while leaving a significant amount of cost allocation to beneficiary funding, will continue the cost allocation wars here at FERC. In that light, I would respectfully suggest that the Commission needs to consider more than just new infrastructure in its cost allocation deliberations.

On a regional basis, cost allocation processes often stall, both within individual RTOs and across them. Resolution of the cost allocation issue for new and existing extra-high-voltage is in front of the Commission. It needs to be expedited to resolve the cross-border allocation issues. AEP, like other transmission owners whose facilities are being used for regional traffic faces a financial burden for our customers and our shareholders. We have been consistently and consciously building a sturdy, reliable transmission system to serve the two stakeholder groups for a full century.

When you think about it, what AEP and the eastern utilities want are no different than what Ohio and the eastern states want. We all want the best for our customers. That means equitable cost allocation throughout the eastern interconnect. While it might seem that physical challenges such as sighting and financial challenges, such as cross-border allocations are unrelated, our reality is that we all have difficulty getting sighting approval in a state that fears that new lines will cost extra for the voters in that state to benefit others elsewhere with no charge. They will be reluctant to do it.

In the Midwest, PJM and MISO, as part of their seams agreement, actually divvied up the AEP's transmission system without compensation. The cost sharing in this environment for both existing and new transmission would spur transmission investment. Early on in the regional era, the Commission attempted to eliminate pancaking through regional design. I think that has stalled to some degree and going forward with some kind of a regional solution for MISO and PJM is a first step and then can be carried to further locations.

Until the Commission can resolve the cost allocation and regional rate design issues, the sprawling interstate system AEP envisions will remain a pipe dream. As we continue plotting down the rocky trail, the concept of regional transmission operation is a good one. It will help levelize prices and improve reliability by minimizing the provisional nature of less integrated transmission grids. But as long as financial arrangements both hinder and produce less than optimum efficiency, the concept is just that, a concept.

CHAIRMAN KELLIHER: Thank you very much, Mr. Baker.

I'd like to now recognize Mr. David LaPlante, Senior Vice President, Market and Systems Solutions, ISO New England.

MR. LaPLANTE: Good afternoon. Thank you for the opportunity to discuss seams issues and other things affecting interregion trading today.

We've been working on these issues in the Northeast since 1999. We started in the New York markets, raised the seams issues and we've worked long and hard to resolve them since then. I wanted to give a little perspective on cost allocation from New England. We had an internal process in New England were we came up with a fixed cost allocation. There was a lot of talk about beneficiary pays. Everyone recognized that calculating benefits would be difficult to do and subject to a lot of contention and discussion. Transmission projects are 30-year projects. What are fuel prices over time? What are the economic benefits that accrue because of improved dispatch? We should get those benefits.

Those sorts of questions are difficult to answer and as anyone who has done a planning study knows, you can get a lot of results out of a single model with a set of assumptions. So rather than go with the beneficiary pays approach, we went with a firm cost allocation. That's not without controversy, as Commissioner Adams, Chairman Adams mentioned today, but it's been very effective in limiting the amount of lack of transmission building in New England. Between 1970 or so and 2000, we've increased transmission into Boston. We've increased transmission in Connecticut. We've solved problems in Vermont. I think there's a lot to be said for certainty in transmission cost allocation if we want to get people to step up to the plate and build them.

Rana mentioned a number of agreements that we've signed to deal with seams. One I'd like to highlight is when New England became an RTO, we signed an agreement with the New York ISO to deal with a number of seams issues that provide a forum by which market participants can identify seams and they provide a process to resolve them. That, in fact, is one of the areas in which we worked through the cross-sound -- the 1385 issue as well as the cross-sound cable issue.

I think we had to change a number of important improvements and the ability to trade between New York and New England, including the rate pancaking that we mentioned, the operation of the cross-sound cable. We have created an interregional planning process. It's not as detailed as we would like. It doesn't have as much teeth as it could have, but we have started joint planning discussions and are planning to get the 1385 line up soon.

Also, on a day-to-day basis, we've made significant improvements in the ability of participants to buy and sell energy between the three ISOs. That's been done by reducing notice time for transactions and improving the transaction checkout processes between the ISOs to make sure that if a transaction is scheduled that it, in fact, will flow. Early on, we had a lot of problems with transactions that were scheduled and didn't occur.

One of the challenges that we will be facing in the next couple of years will be the organization of capacity markets and capacity trading in the three regions. I understand New York in investigating the forward capacity market design, which PJM and New England has gone towards. We're willing to provide any technical support and lessons learned from the development of our market to work with New York to change if they decide to go that way. In the short term, we will work with market participants and the New York ISO to assure that capacity transactions between New York and New England continue to flow unimpeded as we implement our FCM.

In fact, we're having success with that now. LIPA owns a unit in New England that's flowing to New York as a capacity resource. As I said earlier, we've been addressing seams issues since 1999. I think we've had a lot of success, including the ability to buy and sell capacity and energy between regions. As we've done this, we've learned that implementing change takes time and must be done carefully. Seams changes, in fact, take more time than other changes. Because you have two sets of stakeholders, things have to be done in two ISOs.

As the markets have matured, so have the stakeholders and the participation. So stakeholder participation is more vigorous, including participation at the state level. So any change that results in winners and losers is now even more heavily litigated than before.

The other thing that takes time is building the software systems to support the changes. You have a design developed, build and test cycle for good software development that usually takes you at least a year to get any significant change done. These software systems run markets in New England that are worth about $10 billion. We have to be very careful with the software to make sure it's done well. So when we put the cost of that system or those system changes in that context, it makes sense as to why we care for them and why we spend so much money and time on these software changes.

And addressing seams issues, as we move forward, those issues have to be put in the context of all the other priorities and issues that all the stakeholders have in allocating the limited resources of both the stakeholders and the ISOs has to be done carefully. Thank you.

CHAIRMAN KELLIHER: Thank you, Mr. LaPlante.

I'd like to welcome back Michael Kormos, still the Senior Vice President, Reliability Services, unless you had a phone call after that presentation of PJM interconnection.

MR. KORMOS: I think I did okay. I'm still getting paid.

Again, thank you for the opportunity to talk on the RTO seams. I wanted to give you an update on the work we've been doing. My plan is to concentrate more on the MISO PJM seam. Dave and Rana have both talked about the Northeast, so I'll concentrate on the MISO PJM effort and just touch a little bit on what I see the priorities being.

As you can tell from my previous discussions, I believe the PJM/MISO seams agreement is one of the most robust ones in the industry, particularly the congestion management proposal that we've talked about in the past panels. I would also like to talk about what I felt like was a very good cost benefit analysis stage of that project. There are a lot of seams between us, obviously. We've solved a good many of them, particularly in the congestion management side and there continues to be work there.

What we've done is put together a fairly robust cost benefit analysis, which has included the stakeholders to look at the seams, to look at the cost to remove them and then make decisions as to ways to move forward. Everybody may not agree with the conclusions ultimately that were reached. It's been visible. It's been transparent. And in reality, people can bring their complaints to this Commission, if needed, and air out their complaints. But at least the information has been done in a transparent way and we do appreciate the Commission's involvement in those discussions.

I would like to talk a little bit about the accomplishments we've had with the Midwest ISO. Our website and data transparency initiatives, the Midwest ISO has now put in a transaction map much like PJM has for coordinating the data between them. We now have a common website search engine such that our common website you can search both of our websites at the same time simply through one website engine.

We made a number of enhancements on this joint website, which includes a single contour map showing all the places between the PJM and the Midwest ISO, information postings on the operations side and meetings schedules and collaboration, again, where at one site you can see all the activities on a list of service transmission initiatives. We now have much better alignment on our OASIS business practices as far as timing and level services. There's only two exceptions that are relatively minor between the two systems at this point.

We've made a great deal of progress towards a common, long-term transmission service queue. Right now there's a manual process, but we will do the analysis for a long-term transmission request at the same time on both systems in coordinated fashions.

On the planning initiatives, we do have joint transmission planning expansion via the original planning stakeholder advisory group. We have started doing common deliverability analysis, again, for generation interconnections. We will look at deliverability on both systems. We continue to work on the cost allocation issues as was previously mentioned by other speakers.

On the market side, MISO has changed some of roles. We now have better alignment between the FTR products. MISO is also finishing development of ancillary service markets so we can get better coordination on those. We made changes that allow jointly-owned units to move between the two markets fairly easily and freely so that they can choose where they wish to play.

We've initiated the joint loop flow investigation, looking at the effect it has had on both of our markets. Some of the current initiatives we're looking at are, again, working on continued alignment on the FTR side and particularly the long-term transmission rights. We've been working hard on getting convergence of the bus proxies at our seams from a congestion management perspective as well as from an economic energy perspective. We continue working on operating reserves trying to minimize transaction fees between the two areas. We're developing emergency energy agreements and MISO is developing the black start product under market services.

On the transmission services side, we look to automate the current long-term transmission queues so that a single transmission request, which would automatically allow analysis on both systems and a single answer. We're also looking at alternative proposals to a common OASIS. The investment to simply be replaced with one that was not beneficial, but we're looking at ways to still find ways to do joint common stuff on the OASIS.

On the planning side, we'll continue to coordinate the system planning and continue again to try to eliminate durability studies, such that the generator only has to make one transmission request to the two of us and of course, the cross-border cost allocation proceedings are going on.

As we move forward, I would offer that the issues are becoming much more complex. I think we've picked off a lot of low-hanging fruit. As past speakers have mentioned, they are now perceived winners and losers, therefore getting into consensus has become much more difficult in some cases on things like cost allocation. It's virtually impossible. We'll continue to work through the cost allocation process. We'll continue to look at the cost benefits and again, hope to achieve consensus. But at some point, I believe we may need the Commission's help and guidance in getting a resolution to how these can best be resolved.

Just on New York, on the northern side, at the last panel the Chairman asked me which was my worst seam. I'd like to caveat my answer in the context of the operation side. Loop flows I answered the South. As this panel has reminded me, if I look at the planning and cost allocation issues, my northern seam would be getting quite complex in the immediate future. We are looking forward to working with our neighbors to the north on the planning issues and improving the planning coordination, looking to resolve the cost allocation issues and the investment, as I mentioned before, looking at some more permanent redispatch options, building on what we've already done.

Thank you. I look forward to your questions.

CHAIRMAN KELLIHER: Thank you very much.

We have 40 minutes and there are four of us. Why don't we divide that into 10-minute increments. That was pretty easy. I'll start. I don't think I'll use all my time and I hope staff will have questions as well in case the commissioners don't use all our time.

I just had a question about beneficiaries pay projects. How far out -- what kind of horizon do you look at when you're making a determination of beneficiary pays -- three years, five years?

MR. KORMOS: Our planning analysis has actually been on a 15-year basis. But particularly of cost, particularly economically are done 30 years.

CHAIRMAN KELLIHER: Your beneficiary pay allocation is based on that long of a project?

MR. KORMOS: Currently, our beneficiaries pays is being vehemently discussed, in both litigation and in our stakeholder process. The current methodology of beneficiary pays actually looks at a current snapshot as the reliability violation that causes the upgrade to be needed and that is one of the issues being debated. Those beneficiaries, those that are contributing to the reliability now that we see, that violation may be at some point in the future. It could be anywhere from next year to 15 years out.

CHAIRMAN KELLIHER: Okay. I had a question or two for Mr. Bolbrock. You raised a number of points, but one of your injunctions to us was no new seams. But as we saw from LG&E and int he main discussion, that is, in effect, saying don't let anyone leave an RTO because if someone withdraws from an ROT a seam could be created. Is that what you're saying?

MR. BOLBROCK: Interesting. One point I would make, if LIPA were to withdraw from the New York ISO, one of the significant reasons would be the inability to eliminate seams and the inability to prevent new seams from being created. That might drive us away from the New York ISO, maybe to another ISO, but away from the New York ISO.

CHAIRMAN KELLIHER: Are you ties right now to the New York greater than your ties would be to the PJM or to Connecticut?

MR. BOLBROCK: Yes. Not significantly necessarily and there is limited -- from an import standpoint, there's limited ability to get power down through the Hudson Valley through the city. The city is a big sink, so there's some limited ability with the transmission rights and contracts in place.

CHAIRMAN KELLIHER: What would your import capacity be through the city from Connecticut and from PJM?

MR. BOLBROCK: It's about 1400 megawatts through the city. The cross-sound cable is 330 megawatts, but potentially upgradable, somewhat higher. The 1385 line, initially, would be operated at its existing capacity of about 287 megawatts, I believe it is. With some internal upgrades, it could be 400 megawatts. We're actually in the process of replacing the existing cables. That will be done sometime by next year.

The Neptune is 660 megawatts.

CHAIRMAN KELLIHER: Who owns the 1385 line?

MR. BOLBROCK: It's jointly owned by LIPA and CL&P.

CHAIRMAN KELLIHER: Thank you.

I think that's all I have at this point. Why don't I turn to my colleagues? Then, hopefully, we'll have some time for staff to ask better questions than I've been able to muster.

Commissioner Kelly?

COMMISSIONER KELLY: Mr. Kormos, you said you're working on cost allocation methodology. When do you anticipate being able to bring us that?

MR. KORMOS: We have a group working together right now. They're meeting about every two weeks. They have given themselves a mid-May deadline to try to either reach a consensus proposal where there will be a two-thirds majority. I'm not sure. But at least a consensus proposal that we could then bring forward. Or if not, agree that they can't reach consensus and at that point we would file what proposals we had for the Commission to see.

COMMISSIONER KELLY: Thanks. Our experience has been that that's one of the big barriers to getting transmission moving. We appreciate your working on it and being almost ready to bring it to us. Thanks.

I don't have any questions.

CHAIRMAN KELLIHER: Commissioner Moeller?

COMMISSIONER MOELLER: I'll follow up on that.

You also mentioned that your loop flow study, the queue study, the OASIS common practice, I guess, all sound like they're good product, good efforts but do you have a timeline on them variously?

MR. KORMOS: Many of them actually have been completed, some of them. We are working on automating those. There is a monthly progress report posted on the website that we could provide that actually gives the timelines and shows the costs versus the benefits versus any issues we are experiencing with them. We can provide that information. I don't have it on me.

COMMISSIONER MOELLER: I want to talk a little bit about that 1385 line. It seems, at least from what I've heard, kind of bizarre that it would take so long to get a critical piece of infrastructure into the system simply because of some software upgrades. Can you elaborate a little bit more on that?

MR. MUKERJI: It's not due for us. It's due for the new proxy bus. We've done a new one with Hydro Quebec, a new proxy bus with PJM and it is not really a software change. We just changed the data. We also work on what the pricing methodology is that that proxy bus. So the 1385 implementation is not a software-related effort.

COMMISSIONER MOELLER: Richard, do you have any comments on that?

MR. BOLBROCK: In our discussions over these many years, dating many years before Rana drawing New York ISO, it was made fairly clear to us that while there were these other ancillary issues associated with it that software was an issue. In fact, at one point in time it was suggested that LIPA pay and hire somebody to make these changes in the software system. We thought that was a dangerous precedent to set and we did not do that. Perhaps it's more bizarre that it's only these administerial issues that have delayed these for these many years.

MR. MUKERJI: Again, there's infrastructure that we installed about a year and a half ago. The proxy bus is not a new proxy bus which allows for trade between ISOs. It's not a huge software effort. It is more setting up the protocols and looking at market power exercise across the proxy bus that might be studies, but it's not a huge software issue for us.

COMMISSIONER MOELLER: I realize there are two sides to it, but it does seems like for something that was out of the picture for so long, yet it is so significant to an area like Long Island. We could pursue it further another time, but it seems like something could have been done to improve the process. But it does lead to the fact -- I guess it's a tangential issue, but every ISO I visited, software issues have come up as maybe a problem that's ongoing or potentially going to get worse as there are fewer vendors. The question is to whether there should be more uniformity. I guess I'd like your perspectives on that because it's such a critical part of making markets work.

MR. BOLBROCK: I have volunteered to take the lead. Each of the ISOs has their own view on whether their energy-scheduling software is the best, their capacity market software is the best, their ancillary services market software is the best. From my point of view, I'll take the lowest common denominator. Just have them the same, it'll just facilitate in such a simple way the ability to transact business in all of these markets across the borders. LIPA's position would be we'd take the least elegant software solution to any of these markets. Just make it the same in all of these three markets and we'll be really happy.

MR. MUKERJI: If I may just comment on that. I just say for the actual proxy bus that was not a significant software effort in the 72 system. But in general software changes, to say a market participant, which may seem trivial, it usually takes longer and is more expensive than you would think -- an engineering system because as Dave LaPlante mentioned, when you're running a $10 billion market, it is production grade software with a lot of databases and a lot of interrelated things which needs quality assurance testing so that we do not corrupt the $10 billion market.

At first blush, it looks like a simply trivial change, but it takes more time and more money. That's not a question of the complexity of the software system, but the whole difference between, say, engineering simulation software and production software, which runs a $10 billion market. But even that there are coordination efforts among ISOs through the IRC and the ISO RTO consult to come up with common elements with software so we can do these changes cheaper, better and faster.

COMMISSIONER MOELLER: Any other thoughts on that, David?

MR. LaPLANTE: Just to put the software in perspective, when we switched from our interim markets to S&D, we went live in 2003. That was an 18-month, $100 million project to put that software in. Switching software is not something that's done lightly. That's the sort of difficulty we have with standardizing and getting all the same software. We all have systems. They all work well. We've put a lot of time and money into them. So just backing off and changing them isn't something that can be done easily.

COMMISSIONER MOELLER: I didn't want to imply that. I was just thinking, going forward as a Commission, is it a subject that we should be encouraging or looking at? Should it be under our long set of issues to be contemplating?

MR. BAKER: As a person who helps pay for those systems in three RTOs, the administrative charges that we receive, clearly anything that can be standardized and reduce costs, I think, would be considered to be a positive for both our company's standpoint as well as our state regulatory commissions because they have major concerns about costs.

MR. NAPOLI: To a similar degree with what Craig said, I might add that I don't know that you need the same rigor in every area. For instance, PJM is going through some significant upgrades right now. A lot of it driven by the fact that we're building AC-2 and have that ancillary benefit of the upgrades in all those systems. So we're, I think, going to be in a good place. That doesn't necessarily mean that's the case all the way around the country. But I don't know if it, therefore, lends itself to a main focus point. I think there will be some isolated points. Mike can certainly talk more about where AC-2 is at and where the software is at.

COMMISSIONER MOELLER: Time's up.

MR. KORMOS: Again, just to repeat, we are, in fact, placing a large investment in our next generations systems. We are building them and attempting to build them off of standardized system development, not only with the IRC Council, but also internationally as well through the group we deal with internationally. We absolutely agree we are looking to continue to drive our costs down. Standardization is absolutely one way to pause a little bit on the least common denominator. I'm not sure least common denominator is the right answer. I just think we all need to be moving forward. We can do that through a standardized method, but not dropping back to the least common denominator.

COMMISSIONER MOELLER: Thank you.

CHAIRMAN KELLIHER: Commissioner Spitzer?

COMMISSIONER SPITZER: Thank you.

This question may be a little bit afield of seams, but we've heard so much about planning. Virtually every panel has alluded to the joint panels. Here's the last one standing, so to speak, and something is ingrained in my memory just because it occurred shortly after I was elected to the Arizona Commission in 2001.

I made, in hindsight, the mistake of attending a conference, more a technical conference on purchase power agreements. One of the speakers was a lawyer from out-of-state who said, well, one, we need to go see it on behalf of clients. We never assume that future transmission will get constructive. We have to assume the status quo, even if it's listed as a regional planning project because we don't think there is among the politicians the political will, the courage or the competence to actually get it done, which I really wasn't happy here at that time in my life. But I guess in that framework we're in a non-RTO, so the issue is the nexus between PPs and future transmission that may render those PPAs out of the money and the risk here, I guess, particularly where you've restructured -- in those jurisdictions there is a question as to whether generation will get built within load pockets or are those potential projects frightened off or could they be frightened off by planning? How do you see that relationship?

There are a couple of way to skin the cat. One way is to get the generation inside the load pocket. The other way is to build transmission and there's that relationship where there's an act of certainty because sighting is an uncertain process, we know, particularly the really big projects. So how do you all feel about that?

MR. SCARPIGNATO: A while ago there used to be centralized-type planning and you could pick the best, whether it was generation solution in the load pocket or whether it was to build transmission to get there. We're moving more and more to this new role with competitive electricity markets. You really have to balance whether or not the transmission you're building is the right solution or whether generation can get in there.

One way we're doing that is we're allowing something natural to occur in the PJM transmission planning process. We recognize that if we're going to build a 500 KV line they're not going to be built in less than five years. A generator can typically be built quicker than that. When you build the 500 KV, PJM took 22 years. But the point is, if PJM puts out enough information in the transmission planning process about where their problems are, how much it costs to solve it with a transmission upgrade, it's information that generators can use to determine if maybe there's a better market solution potentially in that area.

The other thing you have to look at is in our queues for generation -- where things are located, how things are trending. Certain things you just know. For over 20 years now, the flows from PJM from the west side of Allegheny to the eastern part of PJM before Allegheny even joined, have always been a congestion issue. Maybe it wasn't called congestion back then, but the flows were always tight. Certain things just make a lot of sense and that's what's tends to get built. You talk about what things actually get built.

I think if something is too borderline there would be so much opposition to it getting built it wouldn't happen. What's going to happen is things that are really, really obviously needed are the types of facilities that would go forward. The opposition to building certain transmission usually is pretty high.

COMMISSIONER SPITZER: It's interesting you mention that. I remember as a kid growing up in Philadelphia. I was born in Pittsburgh. At that time, both sides of the state there was talk in the early '70s of building a transmissional line along the Pennsylvania Turnpike. This phenomenon of west to east for 35 years. You know, the last time I checked I didn't seen any transmission lines along the Turnpike.

I guess the question is you have a potential paralysis here were a generation could be rendered out of the money by that transmission line. Similarly, a transmission line could be rendered uneconomic if there's generation put in and as you know, particularly for gas turbines by deployment time.

MR. BAKER: I think, obviously, that problem does exist. When I think back a little on the history of AEP and what I kind of look at in the future, what happened with the markets, to a great extent, is people located generation where it was economically efficient to do it, where it was water, where it was gas, where it was coal and then built transmission to get it to load centers. There has been talk of changing that paradigm. But going back to the interstate concept, we need to get to wind. We need to get to the other types of new resources. We need to locate coal, when you think about it, where you're going to have a place to capture and store the CO2.

When you think about that, I think we're going to be moving back to a spot of locating the generation where it's the most economic fashion to do generation. Transmission tends to be cheap. I realize that's almost a silly statement with the dollars we're talking about, but when you compare, once again, the cost of transmission with the new projected costs of baseload generation transmission still is cheap and I think so. We're going to be back to locating back to where it makes sense to get the resource.

COMMISSIONER SPITZER: You move a little bit away from this concept of the generating plants being -- I won't say random, but as opposed to the former centralized system. The whole purpose of decentralizing generation. It still can be built on a merchant basis, but the locations will be more akin to the old IRP process form the '70s.

MR. BAKER: I think it will be more akin to where the natural resources or the location to be able to do what you want to do. You can't just put wind, for example, anywhere. In Texas, we're looking at -- all of Texas is looking at building a lot of transmission because the wind is not anywhere near were people live. And when we look around and try to figure out where to site wind in our service territories, it's clear to us that there are some places where it works and some that it doesn't.

Unless we build the transmission to move it, you're just not going to see those kinds of developments that I think the industry as well as the public wants to see down.

MR. NAPOLI: I'd like to weigh in. I think I have a view a little bit to the contrary. I think there's enough new technology out there that allows you to locate generation where it's needed to be and even closer to sources. But more importantly, I don't know that that's just the only solution or that transmission is the only solution when you look at the big picture, and we talked before about cost allocation being a major issue. I think when it gets to terms of the transmission that's being build I think we need to build transmission, but I think we need to build the right transmission and I still think we need to give markets time to react to provide the right solution.

Ultimately, the consumer wins when the least cost reliable solution is put forward, whether that be transmission generation or demand response solutions. Right now in PJM, since last year where the market efficiency filing has changed the dynamic, we've lost that one-year window whereby the marketplace could respond to a need and say, yes, I'm going to build the generation or I'll put a merchant transmission project in or I'll come up and bring forward these demand side solutions instead of that transmission project. Once you just come forward or just putting rate-based transmission, you've dampened or eliminated the market signals.

Ultimately, a rate-based transmission solution may be the most practical or the final need, but it should not be placed in such a way that it inhibits or undermines the signals to the marketplace to ensure that the right balance and economic solution is out there for the consumer

COMMISSIONER SPITZER: What you're saying is there is a potential for a transmission solution to have the adverse consequence.

MR. NAPOLI: Yes.

MR. SCARPIGNATO: Let me comment real quick on that. Transmission is the facilitator of the marketplace. And yes, it affects the signals as far as going to generation. But it is ultimately what allows the generation market to function where you build a highway somewhere. You probably impact where a Wal-Mart is going to locate. The Wal-Mart still does locate without the highway system.

People really wouldn't travel where they need to go. It affects it, but it still needs to come first in a lot of instances.

MR. KORMOS: Now that you got to hear three of my members give you three different opinions --

(Laughter.)

MR. KORMOS: -- about how we should do planning, you can understand our dilemma. I think it's an excellent question and one we're wrestling with. We're attacking it first by trying to be very transparent, trying to put that information out as much as we can about where the potential problems are when the problems exist, how much generation it would take to resolve and how much demand response would resolve and ultimately what the transmission solution would look like and we're trying to get ahead of it. That's the reason we've gone now 15 years to try to put them out well far enough in advance that people can't see, particularly, the transmission solutions that are needed in the future.

We will always update our models. Every year we will look at all the solutions in that year period and we will reanalyze and we will not be afraid to change our plan. In fact, we've changed our plan multiple times. We've taken lines in. We've put lines back. We've taken them back out, depending on how it served.

I think at this point the best we can do is to make sure it says transparent, to make sure the information is out there and understandable so that ultimately the decisionmakers have to site the line, who will be the states and yourselves, have the information to make the best decisions.

MR. MUKERJI: With resource planning, you make the tradeoffs between the supply demand and transmission. When you go to a market environment, you have a supply and demand, which will be a lot of times merchant with capital at risk and then you have transmission, which is mostly regulated. There is a difficulty in doing the tradeoffs and that's why you come to cost allocation and beneficiaries. That's one of the reasons in New York we concentrated on the reliability aspects in the planning. To concentrate on that reliability of the system, information and congestion to get the market up where transmission lines may alleviate differences in our CMP. In Order 890, we're looking at this economic transmission line and that's something that we will look at and address within New York and on a regional basis.

CHAIRMAN KELLIHER: Go ahead.

MR. BOLBROCK: I find it interesting when it's suggested that transmission is in competition somehow with generation. In all my years in the power industry, I never saw a transmission line that generated a single megawatt hour of power. In New York State we're working a deliverability standard based on the simple premise that consumers shouldn't pay for ICAP that they can't receive. In large part, we hope this will prevent the addition of additional load pockets and provide a proper incentive for generators to locate -- either locate in constrained areas, No. 1 and No. 2 that causes transmission to be build and we hope to have something fairly soon.

CHAIRMAN KELLIHER: Thank you.

Commissioner Kelly?

COMMISSIONER KELLY: Mr. Kormos, I had a question. How do you integrate into the planning process different state policies of one state that wants integrated resource planning and another one that wants least cost planning? How do you integrate that?

MR. KORMOS: Not very easily. We basically use the information that we get from our generation queues. The generation queues are those projects that have been submitted to us. They are submitted to us based on what type of unit they are anticipated to build, the size of the unit and the interconnection date. Every unit that's in our interconnection queues ultimately gets into our planning model, depending on how far along they are in their own process and their commitments.

From the generations side we get those as units come out of integrated resource planning, they will be put in our queues. AEP is definitely one of them that absolutely will put their units in there. We will obviously honor those. Demand side is a little bit trickier, of course. We don't have as good -- a sort of staging of those. We sort of have assurance that they are going to be developed. That we do on the generation side, not that we believe every generator that's in the queue will be built. But as it progresses through and actually starts to construct itself, there will be some certainty. We're actually trying to work with our states to look at the information we can provide them back on the demand side and how they can formally adopt demand side programs, whether conservation, shaving, storage -- whatever it may be and to integrate that back. So that is one of the areas we still want to work on more with our states to find ways of integrating that at the same degree of reliability we have on the transmission and generation side.

COMMISSIONER KELLY: How about as you embark on longer term planning? Will you actually have generators in the queue or are you going to be looking at a time horizon in which there isn't generators?

MR. KORMOS: We have generation in the queues. Everything from simple one-year upgrades to brand new nuclear plants that are being anticipated, at least, at two sites in PJM right now. They're in the queues. They will be counted, particularly in the economic analysis.

COMMISSIONER KELLY: Generators that may not, indeed, come on line?

MR. KORMOS: That is correct. There are also many ways -- we looked at scaling the generation, looking at where existing generation is and simply scaling that up and down and looking at where the queue is doing it. Then we'll run multiple sensitivity analyses to look at if the generation doesn't site where it's at now or doesn't site where it's at in the queue. When you look at the potential effects of our ICAP market in RPM and how that may affect it, if that drives certain investments in certain areas, we then run scenarios against those different capacity situations to see how that changes the answer. We will provide all those scenarios.

We're looking at individuals lines multiple ways, multiple assumptions on gas prices, on emission prices, multiple generation patterns to look at how robust the line is. What we're finding is that at least in the early stages -- because I think we've all agreed the investment hasn't been there. These lines are pretty good no matter which way you look at them. You need the investment. The early ones are coming through pretty strong. No matter how you look at it we need it. I think the future, though, it's going to become much more of an issue. We'll have to continue to work on this.

COMMISSIONER KELLY: Thank you.

CHAIRMAN KELLIHER: I'd like to now turn to staff and see what questions you all have.

MR. KELLY: I think every panelist mentioned, even focused on cost allocation as an issue that needs to be resolved. Most talked about the interregional cost allocation as a difficult issue. Maybe Mr. Baker said it best that President Bush's national electric grid needs commission leadership to get there.

I'd like to ask a question about process as opposed to method of cost allocation. But before I do, there's something I'd like -- Commissioner Wellinghoff is not here, but the President's grid was an energy efficient smart grid. This might be especially effective at implementing it as opposed to smaller entities. But how would you see, Mr. Baker and others, the Commission exercising leadership? I can think of anything from encouraging the industry to fostering dialogues to directing settlements to a rulemaking that says there is only one way to do it, setting aside socialization versus standard method versus beneficiary pays. What's the other one -- participant funding where only a willing beneficiary pays. What process were you calling on us to engage in?

MR. BAKER: You know, I'm really going to throw this back at you and say this is what you're here for. This is the hard call. There i snot going to be consensus. There may be compromises along the way, but as I've talked -- actually, Paul and I talked about it before. He and I would probably disagree 100 percent or 95 percent about what the right answer is. But having an answer will allow us then to go forward and plan -- explain it to our regulator, explain it to our companies and be able to move forward. The trouble is we're on a treadmill of not knowing what the Commission really believes. If we're going to build transmission, what that right cost allocation approach.

Commissioner Kelly, I know you were looking for Mike to come forward with the solution in PJM. I'm not a betting man, but I'd put a lot of bets on that it's not going to be a consensus and it's not going to walk in here with a solution. It's going to multiple choices for the Commission to choose from and I think there have been numerous cases that that question can be dealt with. But I really think it's the hard call and the only way it's going to get done is for you to make it.

COMMISSIONER KELLY: I appreciate you saying that. I actually know that's what's going to happen.

(Laughter.)

COMMISSIONER KELLY: And I just wanted to make sure you're bringing it in sooner rather than later because

I don't think that spending more time on it is going to guarantee a consensus or even probably enhance much of a consensus.

MR. KELLY: If it's one method for a MISO PJM and another for PJM New York and another for New York/New England, is that bad?

MR. BAKER: I have trouble and it maybe be my parochial way of thinking that there really are different ways to do it. There are political compromises, perhaps, that require different things. The orders that I mentioned are the SPP versus the MISO. But as I said, that still doesn't keep it from coming here. As long as there is a debate and there is not a fine bright line, anything that is subject to evaluation by parties for their economic advantage, recognizing these are huge dollar items is going to, I think, to be back in your lap.

MR. KELLY: Putting you on the spot one more time --

MR. BAKER: I don't like that, Kevin, as well you know.

(Laughter.)

MR. KELLY: Are you indifferent then between a solution which is as in New England predetermined so everybody knows what going on, what it is versus as Professor Hogan was recommending. Everybody is case-by-case because we're really going to figure out as best we can the exact beneficiaries and at the end of the process how the cost are divided up.

MR. BAKER: I believe everybody needs to know what the rules of the road are. That's something that comes out afterwards. It doesn't work well and however you do it, it's subject to debate about the inputs around participant funding.

MR. KELLY: I saw some others wanted to speak to this.

MR. NAPOLI: I agree 100 percent with Craig that I disagree with him.

(Laughter.)

MR. NAPOLI: We'll probably continue to disagree on what the right method is, but I do agree that the decision, whichever way, is an ability for us to move forward in whatever manner is appropriate for our businesses. Notwithstanding that that may result in protests, in additional filings and end up at FERC. But at least, it gives a forum to move forward and start to resolve the problems and issues that we have. I think there is one other cost allocation issue, if I may, that didn't come up. I meant to raise it, but we were a little short on time. That may be to keep it in the mix is the concern as it relates to the ability of cross-seams merchant projects, to utilize headroom in the transmission grids that utilities have constructed for use of loads in their own regions.

These merchant projects, again, we're talking about allocation, therefore should pay the full cost of connecting their facilities and that headroom should still be preserved in the manner that it existed before they hooked up. And again, that headroom is reliability projects that were built. Obviously, you can't build to the exact limit to one MVA. There is some headroom at the time you build a project and that headroom is paid for by the transmission owners and for those ratepayers and for the reliability of that region. So this is just another issue of the cost allocation that has to get into the mix, not a rate-based one, but a merchant transmission cost allocation issue.

MR. BOLBROCK: In the case of Neptune, we believe it has paid its costs. First of all, the representative interconnection study was done and paid for the necessary upgrade costs. Secondly, the embedded costs are paid like any other customer at the point-to-point outservice. Thirdly, we allocated a portion of our tech cost. So the position of Neptune would be that we've fully paid for those costs and importantly, the Neptune, which is considered load, that load is not going to grow unlike the other loads in PJM. That load is fixed. There's no growth in that load.

MR. SCARPIGNATO: I was going to answer Mr. Kelly's earlier question about what the Commission could do possibly to help move this along.

Mr. Baker mentioned earlier that it was attention about the existing facilities as opposed to the new facilities going into service. What's happening is loads that have the existing facilities they are wondering if they spread them over the entire area. People who are doing the new facilities they're wondering if they can do the same.

At PJM, we're discussing cost allocation only for new facilities. Nobody's sure if there's going to be a fair outcome. They're not sure what's going to happen to the existing facilities. So if you add it up, using like a DFAX and you ended up socializing all the existing facilities, people would be kicking themselves for agreeing to doing the DFAX while new facilities have the ability. For existing facilities it makes it hard to reach a settlement in EL05021. It would probably be helpful if the Commission ruled on that case, I believe.

Another thing keeps coming up, too. We keep talking about beneficiaries. I'm sure, as Mike is well aware, we all have different definitions of the word "beneficiary." Under a really highly precise calculation that PJM currently uses for new facilities, it's said that a major 500 KV line, a $1.3 billion project that goes through the Dominion territory where I have two-thirds of my load. I don't have a parochial interest in what I'm about to say. I'm going to argue what you would expect me to say. They said that my territory, Dominion, should not pick up any of that cost. According to their calculation, down to the decimal point, it benefitted the MAC region only.

I know from doing my own economic programs, types of things people have looked at it and also looking at the reliability problems in the Northern Virginia area, that that line provides huge reliability benefits to my territory and it also provides economic. But under this highly precise, who benefits allocation method, it's currently filed Dominion zone where I'm located. We're not picking up any costs.

There's two ways to look at beneficiaries. One is on a project-by-project basis. You have Project A in the northern part of the system and you have Project B in the western part of the system and you go Project A benefitted maybe a million customers. Project B benefitted less of the customers. When you start adding up all the upgrades, I think you'll find out that the system benefits supporting the competitive electricity markets, avoiding blackouts, allowing the reserve markets to function and so forth.

What you find out is that the whole is greater than the sum of the parts I guess is the way to look at it.

MR. KELLY: I never had asked questions about current proceedings, but just what process. The staff might have other questions.

MS. COCHRANE: Just getting off of transmission and the cost allocation part, in your testimony about wanting to allocate costs associated with loop flows, we need mechanisms for that. In the prior panel, there was discussion of we can't really identify what is causing the loop flow. I was wondering if you had any thoughts about what kind of mechanisms we could put in place.

MR. NAPOLI: Yes. I don't agree that we can't identify them. In fact, I have a map here of the 2005 that identifies all the loop flows and exactly what they were. I can pull it out, find it and show it to you, but they are identified and I think that the answer to the problem is twofold. I think that the transparency of the data in order for appropriate calculations to be done and costs to be allocated appropriately needs to be done, as Andy described this morning. But I also believe, as I mentioned earlier, that there are physical infrastructure investments that transmission owners can make that can limit these problems, such as we have done.

We don't experience those problems in New York anymore because of that investment we made. These are controllable. The dispatch operators, when they see flows moving inappropriately, can change the angle and adjust them accordingly or they could choose not to if it happens to be a at period when there is no congestion or no cost issues. They can just say, okay, we'll let the loop flow go because it's not causing any cost allocation issues. But they have the ability to affect it. I think that the answer is a combination of investing in physical infrastructure to do it and the transparency of data where maybe the investment isn't worth it and we can buy data and buy algorithm, figure out appropriate allocation of cost, as Andy talked to this morning. I think that approach can solve it. But PJM has done a good job of identifying where the loop flows have occurred.

Here's my map. And in fact, have shown the ins and outs for each seam and where they've occurred. The data is there and I think the ability to do it is there.

MR. KELLY: I think we're through.

CHAIRMAN KELLIHER: Any other questions?

(No response.)

CHAIRMAN KELLIHER: I want to thank each panelist and this panel as well as the earlier panelists. You've given us a lot to think about and we've covered a lot of ground today. I think we'll have to consider what our next steps might be. Thank you very much for all your help today.

(Whereupon, at 4:35 p.m., the above-entitled matter was concluded.)