BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Project Number:

DEMAND RESPONSE IN : AD07-11

WHOLESALE MARKETS :

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Room 2C

Federal Energy Regulatory Commission

888 First Street, NE

Washington, DC 20426

Monday, April 23, 2007

The above-entitled matter came on for technical conference, pursuant to notice, at 9:05 a.m.

BEFORE:

JOSEPH T. KELLIHER, CHAIRMAN

APPEARANCES:

COMMISSIONERS PRESENT:

CHAIRMAN JOSEPH T. KELLIHER

COMMISSIONER MARC SPITZER

COMMISSIONER PHILIP MOELLER

COMMISSIONER JON WELLINGHOFF

P R O C E E D I N G S

(9:05 a.m.)

CHAIRMAN KELLIHER: Good morning. The panelists are already up, and why don't we close the doors and begin?

I want to welcome everyone to this important conference. The purpose of the conference today, is to explore the role of demand response in wholesale markets, with an emphasis on the organized markets.

Demand response can be defined in different ways, but one definition of demand response, is changes in electricity usage or consumption by retail consumers, compared to their usual or normal usage, either in response to higher prices, or in response to some kind of incentive payment.

An inadequate demand response is a flaw in wholesale operations. It results in greater peak prices, higher average prices, greater price volatility, greater generating capacity needs, and greater environmental impacts.

Earlier this year, the Commission launched a new initiative to examine wholesale markets and to identify the challenges to those markets, and to try to develop solutions.

I think it's clear that inadequate demand response is one of those challenges. The question is not really whether it is a problem or a challenge in the existing wholesale markets, but really what is the appropriate solution and what actions could FERC take to improve demand response?

Now, there's a legal distinction between retail and wholesale markets, but there is clear interplay between those markets. I think lawyers are more comfortable with the distinction between the two worlds than economists might recognize.

Since demand response revolves around individual and collective actions of retail consumers, it is an issue that is important to our state colleagues.

Now, inadequate demand response is a problem in wholesale markets, and, I submit, it also is a flaw in retail markets, when it results in higher average prices paid by retail consumers.

Because of jurisdictional issues, it's important that we work closely with our state colleagues, but I think state and federal regulators and state and federal policymakers both have the same goal in mind: We want to improve demand response, in order to lower costs to consumers, to improve market operation, and I want to welcome the participation of our state colleagues here today.

I just want to particular thank our colleague, Commissioner Wellinghoff. He has shown tremendous leadership on this issue. He's take a leadership role in our federal/state relationship, in improving demand response, and he's also played a major role in shaping the conference today.

So I just want to thank Jon for all of his leadership, and, I think that at some point, I will probably turn the gavel of the meeting over to you, but thanks for playing such a major role in shaping the conference. I'd just like to recognize you for any comments you'd like to make.

COMMISSIONER WELLNGHOFF: Thank you, Joe. I do have some short comments.

Good morning. This technical conference was initially conceived to examine the potential role of demand resources in upgrading the transmission system and to explore methods for compensation to demand resources may fill such role.

The Chairman suggested to me, though, that we expand this conference to examine demand response in wholesale markets more broadly, and, Joe, I want to thank you for that. I think that's what we're doing today, is, looking at it in a more broad sense.

The first job is to ensure that wholesale markets provide a reliable supply of electricity to customers at just and reasonable rates. We do this, in part, by designing and monitoring markets to operate efficiently and by encouraging smart investment in the operation and expansion of our transmission system.

I believe demand resources can and should be an important tool in market operation and transmission expansion. Demand resources can discipline peak market prices; provide a hedge against volatile fuel prices, and potentially be a cost-effective means to delay or defer transmission expansion or to improve the efficiency of transmission upgrades.

It can also be a cost-effective tool in reducing greenhouse gas emissions and preserving our environment through the reduction in peak demand, the reduction of reserve requirements, and the deferral or delay of new capacity additions.

A recent Gallup Poll found that American consumers prefer, by a ratio of 2:1, solving our nation's energy problems through efficiency solutions such as demand response, over an emphasis on more energy production.

The Commission has seen the operation of demand resources in markets. The Commission Staff has reported to us that the total level of demand response reductions achieved by ISOs, nationally, on peak days during the summer of 2006, was over 8800 megawatts.

These demand resources achieve reductions between 1.4 and four percent of ISO system peaks, with load reductions in load pockets such as Southwest Connecticut, as much as six percent, and with reductions in market clearing prices between $100 and $300 per megawatt hour.

These market clearing price reductions mean that consumers in this country, saved hundreds of millions of dollars last summer alone, due to the use of demand response.

Currently, there are several initiatives underway by the Commission or RTOs and ISOs under our review. to integrate demand resources into ancillary services, capacity markets, mandatory reliability standards, and transmission planning.

I see this conference as an opportunity to take stock of where we are with demand resources in wholesale markets, and to discuss where we still may need to go to make wholesale markets operate even more efficiently, in order to save consumers more money.

Today we also want to explore the technical feasibility and capability of demand resources to cost-effectively integrate into the transmission planning process.

As part of the modernization of the transmission infrastructure, EPAct 2005 provides that the Commission shall encourage, as appropriate, employment of advanced transmission technologies. These include the hardware and software of demand resource projects such as energy storage devices, distributed generation, and loads directly controllable by the transmission provider.

If investment in demand resources can be part of the transmission infrastructure solution in a cost-effective manner, then we need to explore the possibility of mechanisms to compensate consumers to provide such demand response infrastructure upgrades. Thank you, Mr. Chairman.

CHAIRMAN KELLIHER: Thank you, Jon. I'd like to recognize Commissioner Spitzer.

COMMISSIONER SPITZER: Thank you, Mr. Chairman. I think a lot has been said that I would concur with, both from you and from Jon, and I would like to echo my admiration for Commissioner Wellnghoff's leadership in this area.

It's very important, and demand response is, arguably, one of the most important things you can do for consumers.

Now, we've discussed the analytical distinction between wholesale and retail, which poses some regulatory challenges between federal and state regulation. We've discussed some of the economic distinctions between wholesale and retail markets.

The customers, for them, it's very difficult for them to distinguish, and that requires us to roll up our sleeves and find innovative ways to achieve our objectives. One of the main reasons that this issue obtained great importance for me when I was in Arizona, was the efforts of Mr. Schlegel, who I believe is here -- there he is. It's 6:00 in the morning in Pueblo, so we appreciate you being here.

I do notice in his biographical materials, that Mr. Schlegel has given a great deal of emphasis to his work in New England, to make we Easterners feel comfortable. I appreciate that.

But we are really getting -- drilling down this morning and this afternoon, on important issues. There have been a lot of materials that were submitted. I appreciate those. I'm going to work my way through them, and look forward to this morning's and this afternoon's panels.

Again, this topic is one of the most important, if not the most important areas that we can provide direct benefit to the customers of this country, and, therefore, is extremely important. I thank you.

CHAIRMAN KELLIHER: Thank you. Well, without further ado, unless -- are there any announcements that Staff has to make, before we go to the panelists?

(No response.)

CHAIRMAN KELLIHER: No? Great.

Why don't we now recognize Andrew Ott, Vice President for Markets, with PJM Interconnection. Welcome.

MR. OTT: Good morning. Thank you, Mr. Chairman. I appreciate the opportunity to come here today to speak to you about this important topic.

My role at PJM is to ensure the markets are robust, competitive, and operate efficiently, and integrating demand response into those markets, providing elasticity on the demand side, is fundamental to ensuring that goal.

Over the past several years, demand response has evolved from just a program, into being an integrated part of the market. What we've seen over the past three years in PJM, is, every revenue stream that generators have access to, demand response now has access to those same revenue streams.

Some of the very important success stories, I'll cover in some detail later, including the capacity market into synchronized reserve markets. Those two have developed significant business opportunities for demand response, where you actually see new investment.

What we've seen over the past years, again, is a growth in energy response, as was quoted earlier. In my testimony, I actually show the megawatt hours of demand response that PJM has seen over the years.

As to what we've seen, there are several things I'd like to point out: The first thing we've seen, we've decided to adjust the growth in megawatts, megawatt hours, if you will. We are observing more recently, response in off-peak times or times when we're not at the super-peak level. We're actually seeing increased megawatt amounts, which, again, is indicative of the fact that if the demand response can more efficiently get in there, they can help us just in the day-to-day operations, shaving some of the morning peaks.

Customers have gone beyond industrials, and now we have universities and hospitals actually participating, and I think one of the big benefits we've seen -- the curtailment service providers are essentially becoming more innovative.

They're actually providing a very valuable service, because each individual entity who can provide demand response, can't afford to take the time to understand the market in depth, the wholesale market, so you have curtailment service providers, actually providing a function to provide commonality, to allow those megawatts to come to the market. That's absolutely valuable, and we see their actions every day.

I turn now to the capacity market. The recent capacity market, the RPM, was recently implemented. We actually saw new demand response offerings and stuff we hadn't seen before.

I don't have a number on exactly how much was new of the 127 megawatts that cleared in the first auction. The number looks small, but you have to realize how quickly that auction came up, and we expect, obviously, much, much more in the future.

But we did see that some of that 127 megawatts was new, that we had not seen, so it obviously is indicative of new investment.

The other thing about the capacity markets, is that we've maintained the short-term demand response.

We also have synchronized reserves. In my testimony, I allude to the synchronized reserve, the growth of that product. It is, again, a unique investment opportunity for demand response, because they can essentially provide a standby service, continue to do their business, and about once every three to six days, they may be called upon to provide quick response.

Again, that fits well, from what I understand, with their business models, and, again, is indicative of incentive for investment.

If I look to the future, the coordination of demand response efforts amongst the RTOs, we have the IRC

Council and the Markets Committee of that Council. We're actually looking at doing a study, and we are in the middle of a study on the effects of demand response and how the markets support demand response.

We're also looking at barriers, again, from a interregional level.

We look to MADRI. MADRI had identified, as I highlight in my testimony, some barriers to demand response. I think what we see, though, is the key barrier, I believe, is that we need to get more common standards across the entire wholesale marketplace.

In other words, we need to interact with the states, as we are. We created a Demand Response Symposium, that we're having in May, to try to look at how do we get more standards across to lower the cost to the curtailment service providers, of actually doing business across the different jurisdictions.

And, again, I would like to emphasis that the retail/wholesale interface, as you've alluded to, has been an important area. We are also going to look at that later this year, and have a symposium on that item itself, because that will help us to identify these -- call it discontinuities or barriers.

I appreciate the opportunity to speak to you, and look forward to your questions.

CHAIRMAN KELLIHER: Great, thank you, Andy. I'd like to now recognize Henry Yoshimura, the Manager of Demand Response with ISO New England. Welcome.

MR. YOSHIMURA: Thank you, thank you for the opportunity to appear before the Commission. It is very important for demand to participate in the electricity markets, especially in New England.

Peak demand for electricity in the region, is growing faster than the rate of overall consumption. The result is that we need to build a lot of generation capacity to serve very high demand a few days of the year.

In 2006, New England set a record of over 28,000 megawatts for peak demand, yet there were fewer than 60 hours in the entire year when demand was over 25,500 megawatts.

It's expensive and inefficient to build infrastructure that is only needed a few hours in the year.

As the Commission is aware, ISO New England has a strong track record of developing programs for customers to respond either to reliability events or high prices. Demand response resources produced more than 600 megawatts of demand reduction on August 2, 2006, when New England set an all-time record for peak demand.

The reduction included the combination of responses from customers and ISO's reliability programs and price programs. ISO is currently implementing a demand response reserves pilot program to determine if small generation and demand response resources of less than five megawatts, can provide a functionally-equivalent reserves product.

There are currently more than 900 megawatts of demand response resources enrolled in ISO's programs, the vast majority of which can respond to reliability events within 30 minutes. We see significant potential, however, for demand resources in New England to exceed what's currently enrolled in ISO programs and what's been developed by utility-sponsored demand-side management programs.

This potential is being demonstrated through the new forward capacity market. The forward capacity market will use a competitive auction to procure capacity to meet New England's installed capacity requirement, several years into the future.

The FCM is the result of extensive stakeholder discussions, they have recognized the value of meeting the ICR, either by increasing supply or reducing demand.

As a result, both demand and generation resources will be eligible to participate, and we expect a portfolio of supply and demand resources to be selected.

Innovative market rules were developed to recognize the different characteristics of demand resources.

Some are passive, such as energy efficiency; others are active, such as real-time demand response triggered by notice from the ISO.

Some are weather-sensitive; some are pure demand reduction, while others rely upon energy output such as distributed generation.

Accordingly, the FCM rules recognize five different types of demand resources that will have the opportunity to participate in the new market.

Pioneering measurement and verification arrangements, will ensure that demand resources meet their capacity commitments. Like supply resources, demand resources will have to perform to get paid.

There will be specific performance hours when reductions from each of these resources will be measured and verified. The pay-for-performance provision and the eligibility of demand resources to participate, were priorities in developing this market.

The initial results for the show of interest for the first auction, resulted in applications for more than 2400 megawatts of new demand resources. This includes a combination of energy efficiency, load management, generation, and demand response.

The majority of the resources are being proposed in Massachusetts and Connecticut, two areas that have long been identified as constrained areas in the region's power system.

Eighty percent of the proposed megawatts came from unregulated merchant providers. Not all the projects submitted show of interest applications, will qualify clear or perform in the new market, however, in ISO's view, competitive, transparent markets, are showing strong potential to attract capital for new demand resources.

Efficient markets need demand-side participation. It helps protect against market power, expands resources available to maintain reliability, and it helps control costs.

Establishing stronger linkages between wholesale and retail markets, would enable further demand-side participation in the wholesale electricity markets.

ISO has sponsored extensive analysis and participated in state retail rate design proceedings to encourage dynamic pricing to align retail prices with wholesale power costs.

This would allow customers to better control their electricity costs and reduce peak demand on the power system.

We believe that New England's market design provides a strong platform for continued development of the region's resources. Thank you.

I should also mention that, along with my statement, I provided written responses to the Commission's question and a PowerPoint handout describing the forward capacity markets, so that's with you.

CHAIRMAN KELLIHER: Great. Thank you, thank you very much. I'd like to now recognize Glen Perez, the Internal Audit Manager at California ISO.

MR. PEREZ: Good morning. I would like to thank you for inviting the California ISO to talk here today about demand response, as well as thanking you for sending David out to talk to us in California in January for our Board of Governors and our officers at a Market Issues Forum on Demand Response.

California is making great strides in developing the infrastructure and putting in the market rules for allowing more demand response to participate in the wholesale market.

The California ISO has been involved in bringing demand response to our markets since 1999. We created the Participating Load Program, which allows loads to participate on equal footing with generators in the non-spin ancillary service market. Loads can participate year'round in that program.

We also have experience in developing, implementing, and settlement of emergency demand response.

In 2000 and 2001, we grew concerned about the investor-owned utilities' interruptible programs.

For these summers, we implemented a trial emergency demand response program and a day-ahead bidding program. By 2001, we had enrollment of over 1,000 megawatts, however, events such as creditworthiness caused us to end these programs.

These experiences have taught us four important lessons: The first, that California ISO must get the market right for demand response to be integrated into the wholesale market.

Second, we must work closely with the state agencies, FERC, investor-owned utilities, and load-serving entities.

Third, aggregators can bring new customers and grow programs, and, at the same time, provide reliable demand response quantities.

Fourth, we must understand the end-users' needs.

Our experience in 2006: As you know, we had an extremely hot summer, as well. We exceeded our one-in-ten forecast, and on July 24th, our new peak was reached at 50,270 megawatts.

The three investor-owned utilities activated their demand response programs, through various triggers, in July, and in that summer, we expected approximately 1300 megawatts of demand response in July.

California is committed to increasing its program participation in 2007, and new programs are being added and existing programs are being expanded.

The values of increased megawatts will be available later on in a few months, however, recently we've met with the three investor-owned utilities and the California Public Utility Commission, and we are working closely with them to understand the new enrollment.

We also have discussed that during the peak days and the challenging periods during the summer, we will discuss on the peak day calls with operations, the capability of each of the demand response programs.

The California ISO is actively involved in a multifaceted process to encourage more demand response in the wholesale markets, and, first and foremost, is implementing our market redesign.

This will provide the foundation for an integrated forward market, and provide the needed day-ahead pricing. Internally, we've created a Demand Response Steering Committee, sponsored by Chuck King, the Vice President of Market Development and Program Management, and the Committee will have members from Operations, Policies, External Affairs, Transmission, and other subject-matter experts.

In addition, the Department of Market Monitoring will be involved.

The ISO clearly must work closely with the California Public Utilities Commission, the California Energy Commission, and the utilities, and scheduling coordinators.

Working with the aggregators that have successfully brought demand response to other states and the ISO, is needed.

We are very encouraged that the California Public Utilities Commission has approved the use of aggregators in the investor-owned utilities' programs.

The ISO has identified demand response as a critical item in our five-year strategic business plan. We look forward to working more closely with the entities to achieve our goals laid out in the Demand Response Road Map.

However, we recognize that demand response programs are not the final destination, and that the destination is to watch demand response participating in fully-integrated market.

I'll also say that I will provide written comments later on, but I did bring the nice weather here today.

(Laughter.)

CHAIRMAN KELLIHER: Thank you. I'd like to now recognize Mark Lynch, the President and Chief Executive Officer of the New York ISO. Welcome.

MR. LYNCH: Thank you for the opportunity to address the Commission on the important issue of demand response in the ISO market.

We have submitted written answers to your questions, and we'll have copies of that document available in the back of the room a little bit later.

This morning I'd like to share with you, some highlights of the NYISO's demand response programs that will illustrate for you, those programs and how they have enhanced the efficiency of the NYISO markets.

This conference focuses on the integration of demand response in the wholesale electric markets. The NYISO Board of Directors and its stakeholders recognized, from the formation of the NYISO in 1999, the value of integrating demand response into our markets.

Since 2000, the NYISO's staff has worked with the stakeholders to develop what many regard as the most advanced market for demand response in the U.S. and a model for others to adopt.

During peak periods, the NYISO demand response programs have proven to be a major contributor to maintaining grid reliability and the stability of our markets, and we have called upon them on 17 occasions for

111 hours since 2001, to meet peak load or to address voltage concerns.

New York State saw the benefit of our continued commitment to demand response and the demonstrated success of our programs by their contributions during last summer.

The summer of 2006 tested New York's bulk electric system and we were able to meet the challenge.

Demand response played a very important role in this effort, by providing voluntary load reduction on six occasions; five of them to address concerns in the New York City area.

On August 2nd, our peak load was 33,939 megawatts, 33 percent more than our peak just ten years ago, and the actual peak was 5.8 percent greater than in 2005.

Now only did NYISO serve its own load, we were able to make emergency energy available to our neighbors. Between 12:30 and 5:30 in the afternoon of August 2nd, the NYISO supplied as much as 1300 megawatts to ISO New England.

The NYISO's demand response programs, both energy- and market-based, supplied almost a thousand megawatts of load reduction for five hours that day. That amount of load reduction is just under three percent of the peak load in the entire state, and is equal to approximately two medium-sized generating facilities.

Over the course of the summer of 2006, demand response provided nearly 16,500 megawatts of load reduction, more than any previous summer.

Currently, the NYISO offers two programs which use demand-side response to avoid short-term reliability problems, and a third that offers load the opportunity to economically offer their load reduction into the day-ahead market for energy.

The NYISO is currently developing further enhancements, which will allow demand response to participate in its ancillary services program, and that enhancement is planned to be implemented by year-end.

There are two programs that pay customers to curtail usage or operate distributed generation during times when reliability of the electrical grid could be in jeopardy.

The Emergency Demand Response Program, which is strictly voluntary, compensates participants for verified energy reductions. Consumers that participate in our installed capacity market and special-case resources, are obligated to reduce the load for specified contract periods when they are called. They receive monthly capacity payments, as well as the LBMP-based energy price, when they are required.

Between May 2001 and March 2007, the NYISO's reliability-based demand response program grew from approximately 200 megawatts to 1615 megawatts.

The number of end-use customers participating in these programs, grew from about 200 in March of 2002, to over 2500 today. Roughly one-half of these customers, representing one-third of the total megawatt load reduction potential, are located in New York City.

The success of the demand response program in New York, has been greatly facilitated by the positive relationship between the NYISO and New York State agencies.

From the beginning, the New York Public Service Commission has been instrumental in the program's success, by encouraging utilities to offer retail demand-side management programs consistent with the NYISO's wholesale design programs.

In addition, the New York State Energy Research Development Authority, NYSERDA, has offered innovative programs to assist participants with load-reduction strategies such as interval metering, emergency generator tuneups, and emissions testing.

The NYISO has a unique structure of shared governance, through which stakeholders work to develop equitable and efficient market rules that will facilitate demand response participation.

A working group dedicated to issues of importance to demand response, provide developers, proposals, and the subject area for approval to the NYISO Stakeholder Committee and to the NYISO's Board.

In addition to work on facilitating demand response to be able to provide ancillary services, this group is actively examining initiatives that include: Automating the registration; performing analysis and settlement of demand response resources; and implementing targeted demand solutions to address local reliability in New York State.

The NYISO's FERC-approved comprehensive planning process, provides a level playing field for demand response that is evaluated on an equal basis with transmission and generation.

We believe that with the support of the New York Public Service Commission, the State is at the forefront to open up wholesale markets to demand, and we feel that this is especially important for the City of New York.

I'll be able to answer any questions. Thank you.

CHAIRMAN KELLIHER: Thank you, Mr. Lynch. I'd like to now recognize Michael Robinson, Senior Manager of Markets with the Midwest ISO.

MR. ROBINSON: Thank you. Thank you for this opportunity to speak before the Commission on demand response in the Midwest ISO.

I'm fortunate to be able to follow my colleagues here, not only today, but also in the design of the markets at the Midwest ISO. We started these markets a little bit later than the other ISOs, and so as an economist by training here, when we set up designing these markets, the first thing I had to do, is sort of look inward and talk with other colleagues about what makes sense from an economic point of view as we move forward in designing these markets?

That's the first thing we do, but, the second thing, is what are the other ISOs doing; what have they already done, so as not to reinvent the wheel. That makes sense from a practical point of view.

Again, we've been fortunate to be able to look across the other ISOs and see what they have done with respect to demand response.

But as an economist by training, you know, markets work best when you have vigorous participation by both buyers and sellers. I think the Chairman did mention that vigorous participation by buyers -- to really have demand response, you have to have end-use customers respond.

And so with that, we have 14 states in our region and we needed close coordination and cooperation with the states to let them promote demand response in their retail markets.

So PJM did drive forward this initiative. I think they call it the MADRI effort. We have looked at that; we've learned from that, and we have created the MWDRI effort, M-W-D-R-I, Midwest Distributed Resource Initiative, that will look closely at the link between the retail markets and the wholesale markets.

That effort has just started, and our next meeting is a week from Friday.

So, you do need vigorous participation. Also, when we set up the market designs, we tried to have as little barriers to entry as possible, and so, from that, the question is, have we set up the rules to provide the services that we need to provide, but also have a -- set up an atmosphere that has open access in fair, nondiscriminatory markets?

And the last thing that makes markets work best, is price transparency and accurate price signals.

By accurate pricing, what I'm talking about is sending the right signal to market participants, that reflect the cost to serve that particular location at that moment in time.

When we get that right -- it's real easy to get that right from the supplier side or the generator's side -- and I think most of the ISOs do that -- we send the price signal that's where the generator is injecting into the grid, at that location, at that moment in time. It's a little bit more problematic than the demand side, because we usually have a price signal across all loads for a particular customer.

I'll be a little bit provocative here and say that right now, the Midwest ISO has no demand-side programs, okay? We do promote demand response, but, by "programs," I mean initiatives that are temporary in nature, trying to promote a certain activity, and usually the programs also -- what's accommodating with programs, are side payments for participation, where those side payments are socialized across a broader market footprint.

And so with our vigorous stakeholder process, we have not -- at the current time, we have not promoted those kinds of programs, but we have tried to, as I said, allow vigorous participation of demand response in our services.

We essentially have five: We have energy markets; we have a filing before the Commission to administer ancillary service markets, and we believe the design there will allow demand response to participate in a fairly vital area.

We think demand response is key, and can really provide a lot of operating reserves. So that's the second one.

Resource adequacy: In our resource adequacy construct, demand response can qualify as providing -- as meeting the load obligation, and so that's there.

The planning process: We are moving forward. We've done a couple of expansion plans to date, and in the next initiative, we're trying to more fully incorporate demand response in the transmission expansion planning process.

The last one is emergency procedures. In emergency procedures, we saw almost 3,000 megawatts of demand response last summer, and so we think we have the emergency demand response initiatives in place and moving forward.

The last thing -- let me mention a last thing here where we think we've got it right at the Midwest ISO. I talked about getting the right price signals to load.

In our market here, market participants can choose to receive prices that reflect where they withdraw the energy, and so they don't have to take a sort of blended rate or a transmission-owner rate or a balancing area rate, but, based on where their customers draw electricity from the grid, they can choose to receive prices that reflect that.

And so we have over 250 load-zone prices in our footprint, and we think that's the first step -- get the market prices right, send the right price signals to reflect the cost to serve that load and then let the market participants decide what they want to do. Thank you.

CHAIRMAN KELLIHER: Thank you very much, Mr. Robinson. I think we have 70 minutes, and I think that's 14 minutes per Commissioner. Commissioner Kelly will join us, probably before this panel leaves, so why don't we -- are you impressed with my math there? Usually, it's 50 minutes and five, and so I had to struggle with this one.

Let me recognize Jon to go first. I just want to give Staff warning that I will probably give you most of my time, because I think I will learn more from your questions than I will from the responses to my own questions.

Why don't we start with Jon?

COMMISSIONER WELLNGHOFF: Thank you, Mr. Chairman. I'd like to start with the panel, with a question for all of you, with the exception of Mr. Ott, because he answered it, which is, what do you each of you see as the key barrier to advancing demand response in your regions, extending it, and also making it more effective, if you have some specific ideas with respect to barriers or key barriers? Henry, why don't you go ahead?

MR. YOSHIMURA: Thank you. I mentioned this in my written responses to the questions, but one of the issues that we have as a system operator with respect to utilizing demand resources more fully, has to do with our ability to see response in real time, and so it's a telemetry and communications issue.

One of the reasons why we're running a pilot program on reserves, is to address that issue, and see if we can find more cost-effective ways to connect small, dispersed resources to the ISO, so we could see the aggregate response in real time.

It's easy to -- it's more cost-effective to use complex and secure communication and telemetry with large generation resources. It costs tens of thousands of dollars, but for, you know, a 300-megawatts power plant, that's not a big cost, but for a small 300-kilowatt demand resource, that could be -- that would be cost-prohibitive, so one of the issues that we need to address, is to find better ways to see, in close to real time, what resources are doing.

We would especially want to use them in reserves -- in a reserves mode.

COMMISSIONER WELLNGHOFF: Okay, Glen?

MR. PEREZ: Like Henry, I agree that in our participating load program, where load has been bidding the non-spin market, we have no problems with the large state water pumps that participate, but because they have interval metering, they have telemetry and that's an experience that they understand, and they have been participating for six years.

However, as you get to the point of aggregating smaller customers, I agree with Henry, that the issue is in the telemetry, and, in some areas, the market settlement.

We have some opportunities, I believe, this year, to work with aggregators to see if we can break down some of those barriers. That's a big plus for us, the way the California Public Utility Commission approved them participating.

We also would like to see more price responsiveness, and, clearly, we need to get the price signals out there, and so the pricing under the new MRTU structure will do that, and with the state's initiative for interval metering, I think we're going to see that those two will come together, and then the last barrier to overcome then, would be retail tariffs.

COMMISSIONER WELLNGHOFF: What, specifically, do you mean by that?

MR. PEREZ: So that the customers can take advantage of the real-time pricing.

COMMISSIONER WELLNGHOFF: Of the meters, okay, thank you. Mark?

MR. LYNCH: Probably a very similar response here. Obviously, we've had pretty good participation on the wholesale level, but I think the real key to really unlock a lot of the potential that's undeveloped in demand response in New York, will be the idea of giving interval metering or advanced metering technology, with the telemetry, down to the real-time residential or large commercial customers, so that they can actually see the prices and then see the benefits of coming in and responding on the demand side, to some of the volatility that you may see in the summer.

We're looking at some of the other programs, as I mentioned, on the ancillary services side. Our difficulty there, is that we truly do co-optimize our energy ancillary services to provide at least production costs, and actually bringing in demand response into that basic program that we have, is, especially on the spin side, adding some difficulty, but I believe, as we go through the summer, we'll be able to implement and provide something by the end of the year, so that we can actually pull those in.

Some of the other programs that we're looking at, that I think will be beneficial and we're doing on a voluntary basis this summer, is actually getting down on the wholesale level, more granularity, specifically with New York City, to have -- right now, we call all of our programs solely on a zonal basis.

Within New York City, with some of the issues we saw last summer, we're putting in a program where we can actually get down and identify the eight load pockets and call them out by load pocket, if we have specific issues within New York City.

So, overall, I think we're developing an evolution here of different types of products that we can bring out to basically enhance of incentivize the demand response providers, but I think that at the end of the day, very similar here, we're going to have to get more real-time signals to more customers for them to be active and respond.

COMMISSIONER WELLNGHOFF: Thank you, Mark. Michael?

MR. ROBINSON: I think the major obstacle in the Midwest ISO, is more of an educational, informational training aspect. It's really in two parts: One is, as I mentioned in my remarks, we do have this MWDRI effort. We have ten or 11 states that are under rate regulation environments, and so this whole link between wholesale markets and retail rates, needs to be addressed, and I see that initiative as doing that and providing that kind of information.

You still have the physical concerns, the telemetry and the meters that the others mentioned, but for us it's really the major obstacle.

The second part of that is more inhouse, I think, and I think it can be overcome, but, you know, if you think about control area operators, they're risk-averse by nature, and the question here is, if you're going to have demand response, provide contingency reserves, operating reserves, there may be, initially, a little bit of discomfort, because they're not as used to it in terms of what they have done in the past, and so I think, there again, it's -- we will look to the other ISOs in terms of that informational training.

I think we can overcome it, but right now, that would be another aspect. We're getting some comfort from having these kinds of resources provide those kinds of services.

COMMISSIONER WELLNGHOFF: Thank you. Now, Mr. Ott, going back to you and your barrier that you discussed, common standards across the entire market, if you could elaborate on that some, exactly what those issues are and what you see as the ways to address that best?

MR. OTT: Well, again, the way -- you know, I look at this more from a commercial perspective. Obviously, we'll have, you know, all the incentives, if you will, to try to support, you know, people investing in whether it be infrastructure, business technology or whatever, I think the key here, just like with the regional market, in my view, at least, is that if you lower the cost of doing business, in other words, if the demand response is different in the way you interact with the customer and the infrastructure you need to build to interact with the customer, it's different in New Jersey than it is in Maryland, than it is in D.C. or wherever and the cost of doing business, again, goes up.

So the point is, if you actually focus -- at least my observation has been that the curtailment service provider, provides, you know, an absolutely critical link, because none of these actual demand responses -- people actually provide the megawatts of response.

They're going to have to be able to follow the market. If we can extend the commonality around the wholesale market, down into the retail jurisdiction as much as possible, that will actually lower the cost of doing business, lower the barrier, which I'll call the cost barrier.

That, really, in my opinion, is the key. Again, of course, to do that, you have to do the common metering, et cetera. But I think -- not here, if you will -- but the real thing we need to crack, is to get that commonality.

That's why we've entered into these discussions on a more broad regional level. We'll have a symposium in May and then one more focused just on the wholesale/retail interface, later in the fall, to try to get those ideas from the CSPs themselves.

COMMISSIONER WELLNGHOFF: That commonality would be something not only from the CSPs, but also from the states, to be onboard with. Is that something that we've got to bring the states to?

MR. OTT: Right. Obviously, each state doesn't have the same, exact auction, SOS-type auction design, but having the ability for the curtailment service providers to define, if you will, common ways of dealing with customers, I think, within states.

In other words, we need to both respect the states' jurisdiction, obviously, and the fact that they have different issues within each state, we also have to respect the fact that the regional wholesale markets would be better served by commonality.

Trying to deal with that fundamental issues, as we're dealing with it head on, that's the problem. We don't want to say that every state has to be the same, because it can't be.

You recognize that, but you also recognize that commonality is the key to lowering costs. That's what we're looking for. At least that's my hope, that we'll be able to do that.

The overheads that exist today, are just too high for this to take on.

COMMISSIONER WELLNGHOFF: Have you got a specific group that's looking at that, and also looking at metering? Is that correct?

MR. OTT: Correct.

COMMISSIONER WELLNGHOFF: I guess I'd take this question to Henry and Michael, because you also have regions that go across multiple states.

Are you looking at similar issues and trying to deal with them? It sounds like you were, Michael, but, Henry, if you want to go first?

MR. YOSHIMURA: One of the -- we run a lot of stakeholder meetings in New England. When we developed the capacity market, that was driven through a stakeholder process. When we developed measurement verification, manuals, and standards, that was done through the stakeholder process.

With respect to going to an area that I didn't mention, but I fully agree with everyone on the panel, that the whole issue of retail tariffs and how they link up with the wholesale market, is a big issue.

We've worked with states through NECPUC, the New England Conference of Public Utility Commissioners, and we are also working with individual state jurisdictions within their rate proceedings.

We're kind of working at these issues, both with individuals states and through stakeholder groups, as well, so we kind of attack the issue from all different directions.

COMMISSIONER WELLNGHOFF: Michael, you alluded to it with MWDRI. Do you want to elaborate any on that?

MR. ROBINSON: Just a bit. There are sort of two different groups working in parallel: One, we have a Midwest ISO stakeholder group, a demand response working group, and that's really looking at what should be done at the wholesale market level, to set up the rules and the design and the compensation, and the settlement, to get fairly active demand response in the markets.

Then, secondly, this MWDRI effort, which, again, mirrors the MADRI effort, is this link between wholesale and retail. The MWDRI effort will look at that.

COMMISSIONER WELLNGHOFF: Henry, I've got a question for you with respect to some more detail on capacity market bids. Can you give me a breakdown on how much of that was energy efficiency and how much was demand response? Also, was it all bid in with respect to peak time? What were the bids as far as over the year, as well?

MR. YOSHIMURA: Sure. I'm going to refer you to a slide I prepared on that, Slide 13 of the PowerPoint that I handed out.

Slide 13 shows a breakdown of different demand resource types for which applications have been made. Let me first point out that these are applications; they're not bids yet.

The forward capacity market has a process called qualification. That whole qualification process starts with this thing called the show of interest. It's basically an application where we take information from generation and demand resources, to see how many resources are interested in participating.

By the way, these represent new resources. These are resources that are not in place currently. They are not iron in the ground; this is new investment that is seeking to potentially participate in the market we're going to hold.

There's a process of qualification where we take more detailed information from each resource proposal, and they qualify to participate in the auction. We do that because the auction itself is based purely on price, and so what we want, is to have physically-viable resources participate in the auction.

So, part one, we get the show-of-interest application; part two, we get more detailed information to verify that these resources are real, so to speak, or basically viable; and then, part three, we hold the auction and then we clear a market clearing price and a quantity, based on the auction. That's how it works.

So, part one, the show of interest, this is what we received from providers that submitted applications at the end of February, so it's about 2400 megawatts.

They are divided up among five resource types.

The resource types are not defined by technology. That is, I think, one of the more innovative things we did in New England, is, rather than say energy efficiency gets one type and demand response, another, what we decided to do, was define performance hours.

That did two things: One, it reduced our need for integration capacity on the system, but, on the other hand, it also recognized how demand resource works.

To give you an illustration, the on-peak resource is a type of resource that reduces demand. Most likely, that's an energy efficiency resource. It's reducing demand over a fixed period of time.

So, in the summertime, we defined it as 1:00 to 5:00 in the summer afternoons, so every 1:00 to 5:00 period for every business day in the summer, that's what we define as the on-peak period.

What we do, is measure the load reduction, by resource, across those hours. That works very well for a resource that is designed to reduce load across many hours, like a lighting program.

The seasonal peak resource, on the other hand, is different. That resource could be energy efficiency, but it's most likely weather-sensitive. In other words, think of an air conditioning measure that's reducing load, but it doesn't reduce load constantly in every hour.

It's reducing load as a function of temperature, or as a function of weather, and it turns out that in New England, weather drives peak.

We wanted to find a resource type that captured the value of that resource that's contributing to peak, and, therefore, we didn't want to throw them into the on-peak category, because it would dilute their resource over too many hours.

So we defined a specific resource type -- seasonal peak -- which captures weather-sensitive types of measures.

There are different performance hours, but they both reduce our need for capacity. I would say that the on-peak are primarily efficiency types of things. Seasonal peak, some are efficiencies like energy-efficient air conditioners, while others could be active load control that's weather-sensitive.

Critical peak and real-time demand response, are dispatchable resources. Real-time demand response is dispatchable, and the ISO gives the dispatch instruction for critical peak.

Those resources respond in the same hours as real-time demand response, but it's not dispatched directly by us; it's by a provider, basically.

Again, these resource types don't follow different -- it defines performance hours, not necessarily technology, and we allow the resource provider to figure out which type they want to be.

COMMISSIONER WELLNGHOFF: Thank you. I have exceeded my time, Mr. Chairman. Thank you very much.

CHAIRMAN KELLIHER: Thank you. Commissioner Moeller?

COMMISSIONER MOELLER: First of all, I want to thank you for making the effort. A few of you have been here on panels several times over the last month or so, so, again, thank you.

It is my philosophy and those of us who have dealt with various aspects of demand response over our careers, that there's a sense of frustration that there is so much potential out there, and yet it just doesn't seem to be coming together.

Yet, as at least a few of you mentioned, with not only consumption rising, but with the peaks disproportionately rising above the level of overall growth, it seems like we're at a time now where we really need to harvest these benefits as demand grows and infrastructure is kind of catching up.

I guess, for all of you, with the exception of Henry -- and this applies to California, as well -- you have footprints that include several -- I'm sorry, not Henry, but you have footprints that include several states.

In the case of California, you have a lot of nonjurisdictional utilities as well. What lessons can you take from the fact that demand response, in different commissions, is treated with different levels of priority and various working groups that you have? Is there anything FERC can take away in terms of a lesson or a relationship we can help to enhance those working groups to make sure that there's a sense of urgency to get things moving faster on this subject?

Andy, do you want to start if off?

MR. OTT: Yes. You're obviously right. In my own jurisdiction, I have the folks, the states who are involved very heavily in the MADRI the Mid-Atlantic Distributive Resource Initiative, and wanting to push that. I have other states who, again, are coming from the sense that demand response is still something that is not necessarily a high priority.

I think the real key, again, is to articulate and I think we are involved in doing that, sort of embracing both and saying it's not that one side has to change or the other has to change; it's to recognize there are differences, and figure out a way to design a system that can accommodate both.

So, I'm sort of sending the message that we're not necessarily here to say we know what you need to change on your side, so let's do it; it's more to come at it from a point of view and say, hey, we recognize there is a difference, and is there a way we can still take advantage from a wholesale level?

The key, for instance, for demand response in energy, isn't necessarily the best business model for someone to do demand response, because they have to essentially producing whatever it is they want to produce.

What we determined, at least in PJM, was, well, the capacity markets, the ancillary service markets, where they just respond occasionally, seems to be a much better business model, and that seems to be a place where we can get more investment.

By the same token, on the state side, the way to get it done, I think, is to recognize there is a difference, and embrace it, as opposed to doing it the other way around.

MR. YOSHIMURA: Well, I think that when the Commission sets a clear policy direction, that helps a lot. For example -- a very simple example -- when the Commission approved the settlement agreement for our capacity market, it had -- it was a broad-based stakeholder group process.

FERC had a Settlement Judge help us achieve that. The Settlement Judge drove that process toward a conclusion.

That settlement had certain aspects that promoted demand response. The Commission approved that, and that gave us the direction.

It was broad, yet it gave us direction to move the stakeholders toward a conclusion.

I think it requires two things: Very clear, direct policy direction, but also giving the stakeholders enough latitude to create a solution. It's a funny mixture of both being very firm, but also giving the stakeholders enough discretion to create a solution that works.

COMMISSIONER MOELLER: Glen, even though it's California, there's a lot to California.

MR. PEREZ: Yes. I'd say we're fortunate that the State has taken a very serious effort to make demand response a key item. Part of their energy action is the number-two item, but I think what supports that, is the active involvement of the California ISO with the State and with FERC.

Again, it's taking seriously, the market restructuring that we're doing. I think it will help push all the entities in the state to participate more with demand response.

MR. LYNCH: Well, I'm a single-state ISO. I might not be able to help you with this.

COMMISSIONER MOELLER: There's a lot to New York, as well.

MR. LYNCH: There's a lot to New York, but I might say that I think the way the Commission could help -- we've had a very good relationship with the PSC. They have put in a lot of innovative programs on the retail side, to actually implement some real-time metering initiatives.

What I would say to the Commission, is, help to encourage that collaborative nature between the wholesale markets and the retail markets.

One of the things that we've found, is that the design they have put in, is very complementary to the wholesale side.

What you don't want to do, is have a retail program that starts to cannibalize your wholesale program in any way, and becomes somewhat redundant, and, therefore, you're counting the same megawatts more than once.

I think it's very important, from my perspective, that the Commission complement and continue to encourage the New York State PSC to work collaboratively with us and with the Commission to develop a program that looks holistically at both the wholesale and the retail side.

COMMISSIONER MOELLER: You answered my next question about what lessons you could provide to us. Thank you. Michael?

MR. ROBINSON: I believe these kinds of conferences help a lot. What's going on this week in D.C., Grid Week, will further the effort.

There's the MADRI effort, the MWDRI effort, and all these are going down the right path, and I think in the Midwest ISO, we're made aware. We started a little slower and a little bit later, because we started these markets later, but we are moving down the right path.

One of the things we're trying to do at the wholesale level, is just provide more information to participants and to the state commissioners.

We're looking -- if we look at a load duration curve and ask the question, well, what happens if you could drop off the top three percent of the load over the year and flatten it out, what would that do to LMP prices in the markets?

That kind of information could be very helpful to the states and make them aware that your demand programs could actually achieve that.

COMMISSIONER MOELLER: I'm guessing that a little later in the day, we're going to hear some testimony from one of the states in MISO, who says that they don't feel they're getting fairly compensated.

Do you want to give a response to that ahead of time?

MR. ROBINSON: Sure. That may be in response to -- we did call on the emergency demand response resources this past summer. We actually achieved quite a bit. We were able to drop load by about 3,000 megawatts.

That enabled us to meet the energy balance and not use the reserves, the operating reserves, to do so, so this certainly did enhance reliability.

One of the issues though, that was addressed as we did the sort of followup analysis, was, are we able to refine how we call on these resources. Essentially, one of the questions that came up, would be, can we create a merit order stack, based on the costs for these resources, to drop their load, and can we be more locational in refining them even further, categorize them better?

I think we can. We are moving forward on doing that, and right now, we are working on preparing some business rules and filing some tariff language at FERC to look at better ways to accommodate the emergency demand response.

COMMISSIONER MOELLER: Realistically, it will be the summer of 08 before you can get that together?

MR. ROBINSON: We're hoping we can get something in by the latter part of the summer, but it does create -- we have a stakeholder process and we need to get consensus from our stakeholders.

COMMISSIONER MOELLER: My last question goes to everyone, except Henry, because of the pending nature of this subject, but I guess one of the frustrations is trying to link seasonality products with annual products, whether your peak is summer or this in the Northwest, in my case, it's winter, whoever is providing that peak shaving in one part of the year, can they match up with other providers to make it more of an annualized product?

The four of you, have you had any experience with that? I presume there's potential out there, although it's maybe hard to make it happen. Andy?

MR. OTT: The only real annual product we have, would be the capacity market, and during the design phase of the RPM, we had discussions about looking at seasonality and determined that we wouldn't actually have the auction itself have the seasons in it, meaning, based on seasonality. This would be annual.

But there were discussions about facilitating the pairing-up issue of one type of resource that could provide it part of the year and another type, the other.

Basically, we didn't go beyond just saying, you know, that would be nice. I think probably the next evolution of the RPM, as we go through, is to create a bulletin-board-type system within the web infrastructure to allow that kind of thing to happen.

MR. OTT: (continuing) There are some issues of confidentiality and things like that, but that's the best approach I can think of short of redesigning the market.

Most of the other products we had actually don't prohibit folks from just participating. It's really capacity that would require seasonality.

MS. PEREZ: For our participating load program in the non-spin market, loads can participate year-round. We've seen that with large state water pumps. So clearly, the types of customers that can do that is dependent on what their activities are.

However, with aggregators getting involved and part of their business model is bringing in different entities, that can be put together. I think we'll see some of the smaller loads being able to participate more.

I would also in that pairing up of resources, one of the things we'd like to see is maybe demand response pair up with wind generation. As you know, with wind, usually in the summer months in California, when it's hot, the wind's not moving too well and wind doesn't show up.

So it will be good to match up those resources as well.

MR. LYNCH: Other than our capacity and the role a special case resource could basically play, we don't have a whole lot of seasonality. Ours is really based more on peak load reduction, which being a summer peaking system we find it most in the summer.

Obviously, hitting a response to a day ahead could participate, but obviously winter prices are a little bit low. That could actually come in. But we haven't seen a need for it at this point.

I think as we develop some of our ancillary services markets, I think you'll see that go through on an annual basis, and they'll be some definite impact in participation.

MR. ROBINSON: I would echo what Mark and Andy said. Our capacity requirements are annual in nature, and the energy markets certainly can be daily or seasonal. What we propose for the operating reserve markets and as we move forward the emergency demand response, it could be seasonal.

But we really haven't addressed the link between winter and summer to date anyway.

COMMISSIONER MOELLER: Thank you.

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

COMMISSIONER SPITZER: Thank you, Mr. Chairman. Commissioner Moeller and I are Thinking along the same lines. I think I'll take a little following up on some of his questions.

You discussed this issue of multi-state RTOs and the complexities of dealing with several jurisdictions. I want to get to more the obvious. The jurisdictions have different regulatory models.

But I guess the question is price. Regulators like talking about price signals. That's a double-edged sword. Frequently, consumer advocates will pop up and say these high prices that you say are so great to incent efficiency in demand response, consumers have to pay the prices, so they're not so hot.

You've got your restrictions with lower prices, so there's less incentive. Then with the single state ISOs, there are service territories within your ISO where there are substantial price discrepancies.

I think Mark you talked about a lot of demand response being available in New York City. Upstate, there are much different prices. In terms of framing wholesale strategies, describe for me some of the issues you dealt with, the tensions between the low- and high-priced jurisdictions or service territories, how you've surmounted them, how you've developed strategies for reconciling different legitimate interests.

MR. OTT: One example I could give you, for instance, we had a fair amount of success in the synchronized reserve market, where demand response came in and provided that.

The price of synchronized reserves, actually there were several regions, if you will, for synchronized reserves, and we saw it develop differently in some areas of the market versus another.

The market actually had a change, where the market collapsed into a single price of synchronized reserves that we paid -- it actually dropped to zero in one portion of the market. So it essentially was educating people and saying that was coming.

In my graphic, you actually saw in February of '07 a significant drop-off in the participation of synchronized reserve demand response. When the price went down in one area, the market price went up in another. So there was a flurry of activity around people saying "Ahh, I'm going to go over here and provide my synchronized reserve."

CSP was saying "I may sign people up over here to do that." So actually reacting and articulating to the market that that's coming. Then you saw -- in March we saw a rebound in the market, because of the structure change and then it's starting to come back.

I think that kind of from a wholesale level, you could help people understand. Is the price change sustained or is it something that's just a blip? Again, this goes back to the same fundamentals with generation, trying to instill confidence in the market.

Price signals are real. They're not just an aberration. So I think in the capacity market, you're seeing the same kind of thing. Certain areas of the market have an extreme price and other areas don't.

The best thing the wholesale market can do is create a dependable, create confidence, if you will, if I'm understanding your question.

COMMISSIONER SPITZER: I do appreciate that answer. Let's take Western Pennsylvania, at historically lower prices. How are you able to assimilate the entities regulated by the Pennsylvania Commission, in terms of cooperating with a program, which might not have as great ratepayer benefits for that region as opposed to New Jersey?

MR. OTT: Again, while we recognize that prices, for instance, for capacity aren't as high in Western Pennsylvania, the recent auction was fairly low there. The actual total energy price, though, locational differences in the energy prices might amount to five or six dollars.

You've still got fairly high prices at the time of the peaks. You have it system-wide. So I haven't found the state commissions questioning necessarily the value of demand response, as much as making sure that the rate structure within the state, you know, matches who gets the money, if you will.

In other words, if somebody is already getting rate relief through their structure, they shouldn't be entitled to an additional payment for demand response. It's really that issue that's more prevalent, I think, than it is the wholesale locational issue.

Again, if I'm correctly understanding your question.

MR. YOSHIMURA: Actually, I was mulling over your question as I was thinking through the question and trying to. Maybe as I respond, you know, we can have a back and forth to make sure I'm responding.

While New England primarily, you know, what causes prices to be higher or lower in one part of the region or another has to do with transmission congestion and losses.

In the state of Maine, the load zone representing most of the loads in Maine have lower prices than Connecticut, and the greater Boston area have higher prices because of congestion issues on the transmission system.

How we respond to that, part of the response is the fact that the prices are higher in some areas. That incents resources to locate there. It's part of the reason why we have that.

If you look at the PowerPoint that I presented to you, if you just go to the pi chart on Slide 14, it shows that most of our resources are located, or at least the demand resources in the market are actually located in two places, primarily Connecticut and Massachusetts.

Those tend to be the ones with congestions. A lot of load there. Part of it is that the market design was designed to drive this sort of solution. The higher the prices, the demand resource providers will go into those areas because the prices are higher.

That's part of the issue. The other is, for example in Connecticut. Connecticut has a certain area within the state that has higher congestion than other areas, Southwest Connecticut.

We've responded there in the past by issuing a specific RFP to locate demand resources there, primarily for reliability reasons. Most of these actions were based upon ensuring that the lights stay on, because there might have been instances where we thought that we would have to shed load a certain number of hours.

So to prevent that, we located or incented specifically to locate demand resources in a specific area. We've done that in Connecticut, for example. That's another way we've dealt with some of these issues.

COMMISSIONER SPITZER: Has there been reluctance or reticence? Obviously, the numbers on the pi chart speak for themselves, either from a state policy point of view.

Pick a name there, you know. They're on the chart to cooperate with regional planning for demand response.

Or are there circumstances when prices in Maine may be low due to congestion in Massachusetts or Connecticut? But demand response would provide a system-wide benefit. Beyond simply the price prevailing in Maine, how analytically do you tackle that type of problem? It's beyond the market.

Analytically, the way I'd look at is there are benefits to demand response in aggregate that might exceed the locational price benefits in each discrete circumstance.

MR. YOSHIMURA: That's true in some circumstances. Resources located in one area of the system benefit other areas. That's certainly true. So there is a socialized benefit as well as a localized one. In fact, we could take that all the way down to the customer.

There's a customer that's totally demand responsive and on the right retail rate regime, we could have very big benefit, and they privatized the benefit. They take home a lower bill as a result. But that in fact, if you get enough of those customers, that also has a socialized effect. It affects the wholesale market. It clears at a lower level and that's socialized across the entire -- I'm not sure that's the right word -- but that effect is felt throughout the entire market. The fact that we have transmission congestion might limit how those effects across the market get played out.

We've look at that. We've sponsored test studies to look at both what is the individual localized benefit of demand response, basically price response versus how does that get played out across the region. Also, we looked at that from a regional point of view.

Demand response, by and large, trades hundreds of millions of dollars of benefit, both individually to the consumer that engages in it and across the region as well.

That is analytically true. We've studied that, and came to that conclusion. That's something that we brought to our New England state regulators, to try to, you know, engage in a conversation of what it would mean to the region to have more dynamic pricing, more retail pricing based on wholesale costs that are clearing in the wholesale market.

COMMISSIONER SPITZER: So the issue is one of extrapolating some of the benefits of demand response in jurisdictions or service territories that may have low prices. I'm running out of time, so let me add one nuance here, which is rate decoupling, which obviously is an issue at state commissions.

Some states, California, have a long history, I think. Someone on the Commission back in the 70's was saying we can't sell electricity like we sell cans of soup. To the extent you have decoupling, it takes away arguably some resistance by some stakeholders to this socialization that Henry discussed.

Maybe in the time remaining, such as it is, we could discuss what has been California's experience with decoupling. Has there been a nexus between that and demand response.

MS. PEREZ: I don't think I'd be qualified to speak to that. I don't want to give you any bad information or incorrect information.

COMMISSIONER SPITZER: Any response on the earlier issue, the degree to which you've got demand response in jurisdictions, where there may be less of a price signal?

MS. PEREZ: I guess I appreciate now more having only one state in our footprint.

(Laughter.)

COMMISSIONER SPITZER: But you have different areas where there's substantial price discrepancies within California.

MS. PEREZ: On the wholesale level, our wholesale market, there's not.

COMMISSIONER SPITZER: But the retail sector?

MS. PEREZ: I see what you're saying in terms of the retail. We have not engaged the other smaller cities or the municipalities that have their own demand response programs, and are running those outside of the wholesale market.

So that's one of the steps that we are planning to take this year, to engage them to discuss those issues.

MR. LYNCH: Maybe going to your original question on the price incentives across an area that's not necessarily homogeneous. We do have three capacity locational areas. Within New York State, we have Long Island, New York City and the rest of the state.

When I mentioned before in my opening comments that a third of the megawatt load reduction is located in New York City, that would tell you that's where probably at least from a capacity standpoint, that's the highest price capacity market.

We do have, though, in Long Island and we do have that in the western part of the state. When you look at the zones, I think A, B and C, those are the three most western zones within the New York market.

In conjunction with K and J, which is Long Island and New York City, they constitute 73 percent of the megawatts. So there is participation out in the western part of the state, even though on the capacity side it's not as high.

On the energy side, when you look at our emergency demand response program, that really looks at a minimum strike price of about $500 a kilowatt hour. That price is pretty much homogenous.

If we call on one of those resources to come in and they'll actually set locational prices, I think it's fair to say that even though we have more issues on peak demand down in the lower Hudson Valley, New York City and Long Island, we do have voltage issues.

We have called on these programs, and we did call on them last summer in the western part of the state, to participate, to help us with voltage issues and they basically get the same compensation as they would across the state on the energy side. Obviously the capacity side is different.

MR. ROBINSON: In the Midwest ISO, at least in the beginning, we tried to keep it very simple. As the wholesale market administrator, what we're trying to do is establish locational prices that are not only transparent but accurate.

So when it comes to accuracy, it should reflect the cost of serving that particular entity at that location. If you're a load-serving entity with multiple withdrawal points on the grid, it's your choice.

You can actually aggregate those and receive an average price. You leave that up to the market participants to voluntarily choose to either price their withdrawal points separately or in aggregate.

As the market administrator, we think that's the right approach. We will make that information aware to the state jurisdictions, the state commissions that have jurisdiction over those entities that they've done that averaging.

But in terms of the price disparity, it's really their choice.

Your follow-up question on what are the benefits to demand response, we really haven't attacked that issue yet. That's to come, I guess.

COMMISSIONER SPITZER: My only comment would be there may be some strategies that could be employed to deal with some of the very legitimate reluctance of low-priced service territories or jurisdictions for full participation, so that an aggregate benefit somehow could be accounted for in an economically rational way. Thanks.

CHAIRMAN KELLIHER: I just have a few questions. I'll have to pick up the remainder of my time, and I guess Mr. Kelly's time.

But let me start off really with a point that was raised in our competition conference in February. The lack of symmetry between the treatment of generation and demand response in the organized markets, I just have a basic question.

Do you agree that there is a lack of symmetry currently in the treatment of generation and demand response under your current tariffs? Andy?

MR. OTT: I think there was at one time in our markets, but I think the efforts we've entered into in the past two years I believe have created symmetric treatment.

I think the access we've made, for instance, in the synchronized reserve market, instead of requiring real time telemetry from a load customer, we looked at what we actually needed for reliability and really what we looked at in synchronized reserve response during the actual event.

We don't even look at individual generator response anyway. We look at aggregate response. So I really need to know what's the effect. For demand customers, they have to give us the real time. Excuse me, the metering the day after so we can verify.

But we don't need an actual operation making those kind of accommodations without sacrificing reliability. I think we've done that. I do believe we have symmetry now across the different market features.

CHAIRMAN KELLIHER: Currently, it's symmetry, or you have less asymmetry?

MR. OTT: I think it's symmetric. I believe the same levels of revenue streams are available, so I do believe we've achieved it.

CHAIRMAN KELLIHER: Mr. Yoshimura?

MR. YOSHIMURA: I believe -- I'm thinking about the question of symmetry. Sometimes symmetry doesn't occur because of some barrier or some technical issue. I would say that in ISO New England, we achieve primarily for the capacity market symmetry on the resource side, in terms of at least the capacity markets.

The problem we face in some of the other markets, such as the reserves market, is I would say that we don't treat demand resources symmetrical with generation resources in that market.

But as I mentioned before, that's primarily a function of the type of requirements that we have for telemetry and communication, and it's not cost-effective for small demand resources.

Then the question is can we find another way to connect these resources more directly with the market or with the operators, so that they could control these resources and see their response in real time. That's one of those things we're working on.

We're not completely symmetrical in that area, but we're working on it. The primary reason we're not symmetric, especially in that area, is because we don't have

-- we haven't discovered that technical solution yet that would be cost-effective for small and dispersed resources.

I believe we achieved symmetry in the capacity market. We're working on the reserves market. The energy market is a different matter. Symmetry sometimes can work two ways. You can have a situation where we're not treating demand resources like generation, and thus have disadvantaged them.

But if you're running the program, it could actually work. So demand resource is an advantage. In other words, you could run a program where you have certain characteristics of that program, which actually boost the revenue stream of demand resource beyond that of a generator.

I think what we've done in New England with our demand response programs focus on the energy portion of the market, is that we've jump-started that market to try to get customers more used to thinking about what the wholesale cost of power is.

At the same time, there are certain aspects of that market where there's forward prices and things like that which generators don't get.

So there's actually certain aspects of that program which we think, in order to get the program going and get customers thinking about pricing, is probably giving them advantages that generators don't have. It can work both ways.

In order to deal with that problem, one of the things we're working on is we're again working on the retail pricing issue if we can tackle that, to link retail prices to wholesale product costs. I think we've solved that problem.

CHAIRMAN KELLIHER: Thank you very much. Mr. Perez?

MS. PEREZ: In our non-spin operating reserve, I believe there's symmetry there. As others have talked about, we don't have load participating in other aspects of operating reserves, in spinning resources or AGC.

So there's not the opportunity for loads to participate in those. That's going to require more technical analysis and research, and changes in regulation.

In terms of our resource adequacy, in the state of California the load can be part of that capacity program. They're treated somewhat separately from generation, where there's a certain limit on the percentage of demand response, dispatchable demand response.

That can participate and account for the capacity set by the California Public Utility Commission. They also -- those loads don't have to bid into the market like a generator would for that capacity.

CHAIRMAN KELLIHER: Thank you. Mark?

MR. LYNCH: As I mentioned before in our planning process, when we go out for our reliability needs assessment that we look at over a ten-year horizon, we do provide on an equal footing the capability for demand response, to provide a solution to meet one of the reliability needs assessable on an equal footing with transmission and generation.

We've only gone through the cycle one time, and we don't see a robust demand side. That's not to say that it won't be forthcoming. When you look at the markets with the special case resources we have, that can actually apply in the participating capacity market.

There is some symmetry there on the energy side, obviously. They look at a fairly high strike price before we call them, specifically on the emergency demand response program we have. The day ahead, they could bid at any time.

Again, it's a function of price. Most demand response providers, especially the large industrials, they're going to have to see a fairly high price to make it cost-effective for them to actually reduce their load and cut back on the product they produce.

There seems to be some, I think. As we develop our market for regulation and operating reserves, I think they will become more. We obviously have to facilitate something that's on our plate right now.

I think we're moving in that direction, and I think over time that there will be a better symmetry.

CHAIRMAN KELLIHER: Thanks. Mr. Robinson?

MR. ROBINSON: I think in our market, there's one major source of asymmetry. That's in the real-time spot market. The way it works today, one, we solve for our least cost dispatch solution. We'll move generators up or down or hold them firm, based on their offers and their merit order stack.

On the demand side though, essentially what we're doing is treating demand. It's like a vertical demand curve. In the day-ahead market, load-serving entities can submit price elasticities and do price response demand bids.

But in real time, what you're asking for, and it's mainly a technical requirement or a technical problem, you're asking for the capability to send a dispatch signal to a load-serving entity based on their demand bids in real time, and have them move up or down based on that.

That's something that we currently don't have. My understanding is a little bit like something of the other ISOs.

I know the California Commission has been engaged in a pilot that actually sends these signals, not to the market participant at the wholesale level, not to the end use customer, but to the appliance itself, to move those appliances up or down based on system needs. That's a major source of asymmetry.

CHAIRMAN KELLIHER: Thank you very much. Why don't we turn the rest of the time, until 10:50, over to the staff.

MR. KATHAN: I have a couple of questions, and then I'll turn it over to the rest of the staff. First of all, to kind of follow up on this last question that touched on a few of them, it has to do with the barriers at this point.

There are economic or demand bidding programs that are in several of the ISOs. Michael was talking about price-sensitive bidding in the day-ahead.

I guess I'd like to have your experience with these programs, and the follow-on to that question is what would a recommendation on how those programs or how energy should directly participate in energy markets. Andy?

MR. OTT: Are you saying how energy bids from demand response? Again, participation in the day-ahead, whether it comes in what I'll call self-scheduled; they just bring it in during certain hours and say "here I am," or they put a price response with parameters and run time or whatever.

In real time, having the flexibility to either be price responsive or self-scheduled, depending on the nature.

I think the key is to open up the market, to allow the customer to articulate how they want to participate given the same rules. Where the generator can self-schedule, so can the demand response.

The demand response wants to follow price, of course as long as they can, provide a signal or respond to a signal.

The other key though, and what we found was to allow the demand responders, if a generator is allowed to give us a minimum run time, why can't a demand response customer say, you know, you have to take me for four hours or nothing. You can't just take me for one.

That was sort of what I thought was our breakthrough, is to give them the same types of treatment. I think we've achieved that. So I think from an energy perspective, as long as you give them all that flexibility, then it's up to them at that point to decide what's best for their business model.

MR. KATHAN: Andy, do you need to have a program?

MR. OTT: You mean a program as in incentives, if you will?

MR. KATHAN: Right.

MR. OTT: Our incentives are actually due to expire at the end of this year. I think my own opinion is I think at this point the incentives should now be targeted.

Instead of just saying there's an ongoing incentive to anybody, the incentive should be targeted towards new response.

In other words, take the monies that you pay for incentives and actually say here, demand response. If you haven't been here before, maybe for the first couple of years, you've got an incentive payment.

So actually use the same incentive dollars to actually target through investment. I think that's probably the best. I think just eliminating them altogether, it's not the time to do that. But I think it's time to start targeting them, to get an actionable response.

It's probably a better use of the time. That's what we're actually focusing on within our own stakeholder project. I don't think it's time yet. We can't declare victory and eliminate them. But we can probably target better.

I'm sorry I didn't answer your question earlier.

MR. YOSHIMURA: I agree with Andy. Currently, we need demand response programs in the economic area. Price response programs, both day-ahead and real-time, do basically jump-start the demand side of the market. Demand participation in the wholesale market.

Where I think the real key is is that this is where this Commission and the states have to really work on this problem together. It's the lack of linkage which is the problem, I think.

We looked at this issue, and we found that more direct linkages between wholesale and retail pricing is far superior than running a program. Running a program, you run into lots of different problems.

Who should bear the cost of the program, because most of the payments that we make because these resources aren't directly integrated into the guts of the real-time and day-ahead markets?

Whatever way, a payment to the price response customer, it's exterior to that market. Then we have to figure out who to allocate the costs to. There's that issue. Besides, you have figure out trigger prices, when do you pay the customers for reducing their load.

There's those issues. It's much more direct for the retail customers and their LSEs, load-serving entities, to work together to figure out the products that retail customers need, to figure out, to determine, to figure out the right mix of what sort of load ought to be on some fixed price. This is what part of the load could be on some variable price.

It could be all the customer's load; it could be a proportion of the customer's load. RTOs are not equipped to make those decisions. Retail suppliers are in a position to make those decisions, working with the retail customers.

I think that's where the function of getting customers to be price responsive to the prices formed in the wholesale market. That's, I believe, the function of getting customers into some sort of price regime and having customers respond to that is really a retail function.

What the wholesale market can do is provide those prices, provide transparency and an avenue for customers and their aggregators to connect up to those prices.

It's much more effective for the retail customers working with their load-serving entities to figure out the best way to both hedge the electricity prices when they need that, and what portion of the load ought to be some responsive rate in order to save money.

RTOs can't make those judgments. Retailers can.

MS. PEREZ: David, as you know in California, we don't have -- the ISO doesn't run any incentive programs. The state runs all the incentive programs.

So there's always the opportunity for the scheduling coordinators' load-serving entities to self-schedule and bring those into the market, as Andy said.

However, our biggest emphasis has to be on our market redesign, and getting the day-ahead and real-time pricing available for entities to use, as Henry said, in their retail programs.

MR. LYNCH: I would just mention on a day-ahead demand response program, I think historically we haven't seen a lot of participation in that program.

Part of that has to do mainly, I think, because the emergency and demand response providers, and the special care resource providers, are on in the same.

When you have high prices, I think you'll find that they will opt into the emergency demand response or special case resources. The day-ahead program, I think, is a program that we are going to continue to look at, to just make sure that we can somehow look at market participation in there.

I don't necessarily think it's a socialized or incentive program. It's something that has a fairly low strike price, $75 a kilowatt hour right now. It's still a program. The prices have to be there or higher for them to participate.

The other two programs, when we have the SCRs in both the emergency demand, it's not necessarily a real-time program. But it's called upon when we do look at whether we're going to have reserve shortages or the peak loads are going to come in and cause stress on the system.

So these seem to work fairly effectively, I think in the sense that they actually provide the peak-shaving that we need in those instances. But they're not necessarily real-time programs.

MR. ROBINSON: David, as I said earlier, the Midwest ISO is not providing any incentives for demand response currently. The question before the working group, as we will follow it, will be whether we should engage in these types of programs or side payments.

But I think also we may be better served by providing a tighter link through this ongoing effort between retail rates and wholesale prices.

MR. KATHAN: Just one quick follow-up, if any of you can answer. I had heard there are various ways besides these incentive-type programs for demand to participate, to be price sensitive. Are there any barriers at this point or challenges on the load side to be able to participate in any of those types of programs, whether it's uninstructed deviations, whether it's the price sensitive bidding or virtual bidding?

Any ideas on any barriers or challenges you've been exposed to?

MR. OTT: I can just comment. I think probably the most significant barrier goes back to if someone provides demand response, are they entitled to the payment, the rate structure thing?

There's a fair amount of demand response out there in my area, in the western part of my system where it's not clear that the customer is entitled to getting the money. They may have gotten rate relief and that whole issue of who's entitled. Is it the utility or the demand responder?

That's more the barrier, I think, right now than the wholesale market.

MR. KATHAN: A question just for Mr. Yoshimura. You mentioned that you had a pilot program for aggregating demand response under five megawatts. Could you elaborate on that?

Who's doing the aggregating? Realistically, how small a load can participate? Which market does it enter into? Just more detail on how that works.

MR. YOSHIMURA: The pilot program that we're running is basically a 50 megawatt pilot program. At least we could enroll up to 50 megawatts and pay those megawatts, the forward reserve market clearing price.

We basically run a separate auction to procure reserves for the system. What we do is take this 50 megawatts; the additional 50 megawatts is off to the side. The market participants agree to pay those 50 megawatts. The market clearing price in the reserves market.

Then what we do is using the same platform that we used to implement our real-time demand response program, which is used as an Internet-based communications system, we basically dispatch these resources as though they're responding to a reserve event on our system.

These are short events. They're more numerous. They're shorter in duration but they're more numerous than events that are emergency programs that are implemented.

Then what we plan to do is collect those data, analyze them, to see whether or not these resources or different categories of these resources are able to respond to these events.

Part of the reason for doing that is partly to educate our own operators as they gain confidence with these resources, and to get some background data on how they respond, and therefore be able to use these resources confidently like they use generation resources.

We plan to run this pilot. This pilot is ongoing. We're going to be doing the analysis on the pilot response toward the end of this year. We're also going to start a second phase, which is basically to look at better ways to communicate with these resources.

We currently have a way of doing that using the Internet, but our system operators, being security nuts, they are afraid of that because the Internet's not necessarily a secure environment.

So we have to think about how to best do this, how to satisfy both our security requirements and be able to communicate with a dispersed set of resources.

MR. KATHAN: Is there a minimum size or effective minimum size if you meet certain parameters that wouldn't be cost-effective?

MR. YOSHIMURA: The minimum size for a resource is 100 kilowatts, though that resource could be aggregated.

So, you know, it's possible for a resource representing let's say residential air conditioning, with 1.5 kilowatts per unit, to aggregate up to the minimum size within a load zone. So that's how it's designed.

So even though a single asset, so to speak, is 100 kilowatts in terms of the minimum size, we allow for even subaggregation. So it's really limitless when you think of it that way.

MR. KATHAN: Thank you.

CHAIRMAN KELLIHER: Any other questions? John, do you have any others for this panel?

(No response.)

CHAIRMAN KELLIHER: Thank the panels very much for your help today. We'll take a short break and remain punctually at eleven o'clock.

(Recess.)

CHAIRMAN KELLIHER: We'll resume the technical conference. If you want to continue your conversations, you have the hallway. I'll ask the second panel to come up, thank you, and we can resume.

Let's start at the beginning with our astute colleague, the Honorable Dan Ebert, Chairman of the Public Service Commission of Wisconsin. Thanks for being here.

DR. EBERT: Mr. Chairman, thank you very much for holding this technical conference today, and other Commissioners, thank you for taking the time.

From Wisconsin's perspective, and I think from the Organization of MISO States' perspective, this is a critical issue for how the markets are functioning, and how they will function going forward.

I think we all recognize that demand response is a key reliability tool. It is a key cost saving tool. What I like, as I have talked to the customer groups in the state of Wisconsin, I have talked about this as empowering customers, giving customers the tools to manage their own resource energy use wisely.

Let them make decisions that best help them, whether it's a residential customer or a large industrial customer.

From my perspective, the demand response programs are really critical to empowering consumers to be able to make their own energy decisions, obviously working with the utilities and in the Midwest, with MISO.

So it's really critical, I think, that you guys are taking a look at these questions. Let me just quickly describe the context in the state of Wisconsin. We have been doing demand response programs in Wisconsin since the 1970's.

We did that because we understood that it was important for us to manage our overall portfolio, working with our utilities, in a way that really did maximize demand response and therefore help us control costs and control the need to build new infrastructure.

We have today about six percent of peak load in demand response. It includes a variety of programs for interruptible programs for the large commercial and industrial customers, to direct load programs for residential customers, real-time pricing, actually more specifically time of day pricing.

So we do have a number of tools that are available today for customers. I think the emergence of the whole markets have given us incredible opportunity to maximize demand response programs.

I think MISO in particular, over the last six months, has really rolled up its sleeves and worked with OMS, to try to understand the complexity of really fully integrating demand response into the market.

But I think those efforts came about because of some pretty significant events last summer that I'd like to just describe for the Commission here today.

We had a couple of days where there were some emergency procedures called by MISO. There were, I think, some challenges in communicating exactly what those procedures meant to individual utilities throughout the footprint.

I believe those communications challenges have been resolved. Certainly, they have improved those procedures. More importantly, I'd like to focus on the economic impact of what happened in those two days on the state of Wisconsin.

What you had is about 600 megawatts of demand side management that was called upon, which meant that there were large companies, primarily large companies in the state of Wisconsin who were required on an hour's notice to turn off.

That had economic costs for those customers. You had Wisconsin Utilities then selling into the market, and I think everybody would agree that the prices in the marketplace, because of a total of 3,000 megawatt demand side management, was called upon.

The overall prices in the market did go down. So there were an economic cost, I think, for our state's utilities. Then to add insult to injury, I guess, we had Wisconsin Utilities that also were assessed revenues sufficient to guarantee payments or penalties.

Again, as I said at the outset, I do believe that a combination of MISO's program working with John Norris, and OMS' own program with Commissioner Bob Lieberman from Illinois, were very focused on this. We have rolled up our sleeves.

But I think the challenges before us is to really make demand side management the effective tool that we all want are really pretty significant, and I think that we do have a ways to go.

Again, I'd like to thank Mike Robinson for his efforts, his team's effort, and all of MISO. They clearly have responded.

I am little concerned that we're heading into the summer peak period, and we still do not have some of the key lessons learned and some of the pieces that Mike has identified and John Norris has identified as the key going forward.

Some of those are not yet resolved. So we are in a situation, at least with the state of Wisconsin, where we may very well have similar circumstances this summer, and that for our customers is an unacceptable result.

Thank you. I'd be happy to take any questions that you might have.

CHAIRMAN KELLIHER: Thank you very mch. I'd like to now recognize Dennis Derricks, Director of Regulatory Policy and Analysis with the Wisconsin Public Service Corporation.

MR. DERRICKS: Good morning. Thank you for the opportunity to come and speak about demand response. This is truly an issue that WPS has supported a long time. We believe it's a valuable tool and able to provide value to our customers.

We also believe that WPS is a leader in demand response. We have approximately 50 percent of our overall load enrolled in demand response programs, in one way, shape or form. We also continually provide 13 to 15 percent of our load as a price-sensitive bid into the MISO Day 2 market.

We also believe that is a valuable tool. We also are 100 percent EMR-deployed. We provide kind of an interesting perspective to the whole demand response.

What I'd really like to do today is to provide just a very brief overview of demand response and WPS. I'd like to describe to you some of the changes we've had to do with some of our programs, to accommodate the MISO Day 2 market.

Third, I'd like to talk a little bit about some of the challenges and issues that remain for us to implement more demand response. First of all, from a background perspective, for our large C&I customers, we have traditional interruptible programs. We have demand bidding programs for short-term issues.

For our small C&I and residential customers, we have the traditional air conditioner and water heater control programs. Recently, we've been introducing critical peak pricing programs. We started with the large C&I customers and this summer, we will be rolling out a program for our residential customers.

We strive to provide value to our customers and demand response is one of those tools. The simple goal is to provide participating customers with an opportunity to better manage electric costs, but not provide harm to the company or non-participating customers.

To do that, you need to have the price reflect cost. From my perspective, that is one of the key ingredients for long-term sustainability of demand response.

The next thing I'd like to talk a little bit about is our interruptible program, and how we modify that to accommodate the MISO Day 2 market. We believe it is a very successful program of incorporating wholesale prices into retail rates. It is similar to any traditional interruptible programs.

It's eligible for customers with 100 KW or more of interruptible load. Customers receiving demand credit reflecting the fact that WPS does not need to buy or build long-term capacity in exchange for that customer's reliability interruptions or economic interruptions.

Economic interruptions would be along the lines of WPS having to buy energy at prices significantly exceeding the price of peaking capacity, again trying to balance those participating and non-participating customers.

During those times, customers could buy through the spot market. Prior to MISO Day 2, WPS controlled and dispatched its own generation into the MISO Day 2 market. That was obviously going to change. One of the programs, we actually had two different types of interruptible programs.

We had a program where customers could nominate the amount of firm demand they wanted to have during the time of interruption. The other one would be the customer could actually nominate the amount of interruptible that they would actually interrupt during an interruption.

For that type of program, the customer, the amount of interruptible load that would be measured would be measured by the fact about what load the customer had at the time of notification.

When we started looking at the MISO Day 2 market, we sat down with our customers, our regulators and our energy supply control folks and talked about what opportunities and challenges the MISO Day 2 market provided.

First of all, one of the key aspect to us is that we no longer controlled our generation. A lot of our tariffs were designed to reflect company-owned generation. Loss of those would trigger interruptions.

The other thing that was quite apparent was that the day-ahead market provided a lot of price transparency, which was a very positive thing, and also provided the ability of get day-ahead notifications for interruptions, something that our customers were not having at that point in time, but would provide a great deal of value.

With respect to the day-ahead markets, we were able to work with our customers, to use the interruptible program to submit price-sensitive bids to the day-ahead market and to the MISO. This provided, again, more price certainty for the customers on a day-ahead basis.

We had to eliminate the fixed interruptible program, because it no longer made sense to call interruptions on a day-ahead basis and have that type of program.

The last thing we were able to do is we were able to give customers a little bit more price certainty with respect to a buyout interruption, such that we would allow them to actually submit bids to us, that we would pass right on to the MISO for higher buyout prices.

In summary, we are providing about 200 to 250 megawatts of price-sensitive bids, which represents about 13 to 15 percent of our WPS load. Just a couple of quick challenges, if I can. I won't.

(Laughter.)

CHAIRMAN KELLIHER: We'll try to work them into a Q&A. Let me recognize Dr. Bernie Neenan, Vice President for Utilipoint International in Syracuse, New York, home of the Syracuse Orangeman, I have to say. As a Georgetown graduate, I'm going to listen carefully to your comments.

(Laughter.)

DR. NEENAN: Being the victor is not becoming.

(Laughter.)

DR. NEENAN: Thank you for providing me with the opportunity to speak today. I'm Bernie Neenan, Vice President of Pricing and Demand Response for Utilipoint.

I will direct my remarks to the questions posed to this panel, however, not in the order that are listed in the agenda, and not with the same degree of emphasis.

For example, as a confirmed neo-Luddite, who believes that the last truly useful technological advance was the corkscrew, I will leave out of this discussion the role and value of technology to enable demand response.

Some see technology as the answer. Others like me, it's still an opportunity, the benefits of which are not fully understood. What has been my experience with ISO-RTO demand response programs is, in a word, exhilarating.

Because of the efforts of ISOs and RTOs in the past seven years, thousands of customers responded to price signals that reflect contemporaneous market positions.

The consequences have been valued in the hundreds of millions of dollars. I find ISO-RTO staff open to new ideas, asked to define creative solutions and appreciative, thoughtful and purposeful analysis, but not afraid to just try things out.

Stakeholders with diverse interests have demonstrated the ability to resolve their differences through fact-finding, diplomacy and the honest pursuit of self-interest. It makes markets work so much better than regulation.

As further integration was required, many ISO and RTOs already have demand response, artfully and fully integrated into the technical and economic fabrics of their markets. In some cases, price and demand response are indistinguishable from their counterparts for scheduling dispatch and remuneration.

The equal pay for equal performance doctrine in the market protocols had that outcome. The question of integrity, however, may be daunting for some, the program disparaging, suggesting that ISO and RTO initiatives are transitive or transitional.

Perhaps that is the appropriate treatment in some cases where load is seen as a resource in the wholesale energy spot market, which has generated intellectual lightening and thunder to the degree that rivals a hot summer afternoon in the South.

The issue has been a boon for economists and those that torment them. The principle is admirable. It influences LMP head-on through the influence of price-setting operations in the ISO, because loads are treated as resources.

However, the same results can be achieved spontaneously and deliberately by customers adjusting their load under pricing plans, often by load-serving entities that link prices to supplies and costs in ways that benefit both of them.

As utilities, RTO programs have demonstrated that they are equivalent, which is preferable. The debate over the benefits of direct bidding is ongoing and intense.

There are net benefits that should be rightfully considered for policy-making purposes. Others condemn them as transfer that represent a redistribution and not an augmentation of societal welfare that can have unintended adverse consequences.

Conversely, spontaneous price response by nature benefits those who undertake it, without the need for additional financial inducement and other customers realize as well, seeing it as a bonus. A later panel will discuss the process of measuring the performance of direct bidding programs, which is not an issue with spontaneously-occurring demand response.

I was an early and outspoken advocate of allowing customers to bid load curtailments as resources in the day-ahead markets as an alternative to demand resources. This shortcoming seemed to be tolerable, at least for a while.

I consider this a stop-gap measure, one of many market transformation initiatives that would serve as placeholders, while retail market alternatives were devised and mature.

Widespread participation in and response to retail pricing programs, however, have not materialized.

The issue we face now is to ascertain how to direct the formation of such a pricing plan. It introduces customers to new behaviors that they can then exercise spontaneously or RTP-type default service programs that accomplish that result better.

There's little evidence to support of defeat either notion on the terms of direct bidding, which in effect socialized the cost better than any retailer can offer. Then if that's the case, the benefits of direct bidding are at the expense of potentially larger gains from spontaneous price response.

Alas, we cannot establish the truth or fallacy of either proposition. Resolution of the long-term role of direct bidding will clearly require greater coordination between ISOs, RTOs and state regulatory agencies.

Finally, is greater coordination needed between wholesale and retail markets? My answer is that coordination will be sufficient on buyers and sellers' electricity, engaged so vigorously that prices truly reflect the value of resources committed, and may eliminate price gaps and other restraints to price formation.

In other words, when the market monitor becomes like the Maytag repairman, forgotten, forlorn and forsaken, demand response will hasten that day. Thank you.

CHAIRMAN KELLIHER: Thank you, Dr. Neenan. I'd like now to recognize Mr. Walter Brockway, Manager of Regulatory Affairs for Energy Alcoa.

MR. BROCKWAY: Thank you. Good morning. Alcoa appreciates the opportunity to participate in this technical conference. I am Walt Brockway, Manager of Energy and Regulatory Affairs for Alcoa. Our group has been deeply involved in developing the company's thinking on demand response.

Briefly, as the nation's largest manufacturer of aluminum and aluminum products, Alcoa is one of the largest consumers of electricity on the North American continent.

The bulk of this consumption, about 2,800 megawatts in the U.S. alone, occurs at aluminum smelters, where we reduce aluminum oxide into aluminum, which consumes electricity.

It has a very high load factor 24 hours a day, seven days a week. We have smelters located throughout the country in a number of reliability regions, some of which are served by ISOs, RTOs, and some of which are not.

Over time, most of these smelters have participated in demand response load reductions. We have demonstrated capability in the New York ISO, ERCOT and PJM, as well as individual electricity suppliers in regulated markets.

In fact, most of the power purchase arrangements with Alcoa smelters have some form of curtailing provisions, and have over the course of time. The ISO is where we have operating smelters, on New York, ERCOT and the Midwest. We did have a smelter in PJM but it's been shut down in 2005 due to our inability to obtain a long-term contract that would allow us to operate economically.

In the New York ISO, our two aluminum smelters have participated in the emergency demand response program, and the installed capacity special case resource program.

We have not, however, participated in the day-ahead response program as yet. Our opportunities to participate in this program are hampered to the exclusion of our bilateral contract.

Additionally, we are awaiting ISO's implementation of its ancillary service market for load participation scheduled for the fourth quarter of 2007.

Of special note here, our smelting facilities were recognized in the NPCC report of the 2003 blackout in the Northeast for their coordinated effort with NIPA and the New York ISO to implement a 60 megawatt rotational load shed program.

These actions were cited as helping to prevent additional residential and commercial load-shedding in the region. In MISO, our Warwick, Indiana smelter located near Evansville has thus far participated by offering energy the day-ahead and real time markets, by reducing production to take advantage of the MISO need for energy during high-priced hours and tight generation periods.

Depending on the price signal provided by the market, a smelter can vary its production by up to 90 megawatts for up to a three hour period. In many instances, we were able to increase production in lower-priced off peak periods to maintain production targets.

In other cases, we were not able to make up production, but we reduced load and in our case helped the power grid and repaid LNP for the energy provided, thus offsetting the impact of lost production.

These actions benefit the customers in MISO by avoiding the start of higher cost generating units, therefore moderating prices for all customers.

At Alcoa, we believe the nation has only begun to tap the considerable potential of demand response to more efficiently use existing energy resources and thereby reduce the human footprint on the environment.

Among the additional steps necessary to realize the potential of demand response are the following: Access to programs. Demand response resources should equal access to the market. I'll skip through these quickly.

Preserving end-use autonomy. One of the defining principles should be that demand response programs preserve the autonomy of the participants. We have clearly defined our commitments. The decision of customers to reduce their consumption must remain with them. Parties need to retain the ability to define frequency, magnitude and duration from which they will participate in demand response.

Non-discriminatory performance standard. A key element of reliability and reliable demand response programs is having providers that are capable of responding when they're called upon, and there needs to be decision-making subject to regulatory supervision regarding whether these resources can actually respond as they are promising and drive down associated risk.

This should not be onerous. No discriminatory price should reduce the quality of service provided, and the ability of utilities to respond more quickly to many forms of generation. Time is a critical element in demand response programs.

The speed, precision and consistency should be taken into consideration by this program cost should be allocated from a causative basis. I'll leave it at that.

I want to make sure that I bring up the fact that we are finally working with Oak Ridge National Lab on methods and means for loads to affect not only our spinning and supplemental reserves, but as a regulation service.

What we have envisioned is for our large loads to receive a frequency response signal from the operator directly to our load and reduce or increase our load to aid in maintaining a system frequency. Thank you for the opportunity. I look forward to your questions.

CHAIRMAN KELLIHER: Thank you, Mr. Brockway. Mr. Giudice, Senior Vice President of Corporate Development with InterNOC.

MR. GIUDICE: Good morning to all. My name is Philip Giudice. I'm InterNOC's Senior Vice President of Corporate Development. I thank you for pulling this panel together and giving me the opportunity to speak today.

InterNOC appreciates and recognizes and foresees the value in demand response. We look forward to continuing to work with you, state regulators and other stakeholders, to help further integrate demand into wholesale and retail markets.

Before I address the questions you've asked, I'll just take a brief moment to tell you just a little bit about InterNOC. InterNOC is a leading developer of demand response solutions in the United States. We currently manage 578 megawatts of demand response capacity across over 1,300 customer end user sites, commercial, industrial and institutional customers.

Our average site produces somewhat over 400 KW. We are active in all four open markets that have active demand response programs in them. That's ISO New England, New York, PJM and California.

We also have several bilateral contacts with utilities to provide demand response capacity directly to them. The "NOC" in InterNOC stands for Network Operations Center. You're all invited to come up to Boston anytime and see our facilities there, where we dispatch those 1,300 sites.

InterNOC's basic business model is to help relieve the strain on the electric grid at the end users.

We utilize the Internet. We dim lights at grocery stores. We turn down air conditioning settings at industrial facilities. We turn on backup generators at data centers and hospitals. We even shift manufacturing production to off-peak facilities.

Demand response in the United States has come a long way over the last several years. I presented that at a similar conference here at FERC about a year ago, and since that time InterNOC has more than doubled in size. There is much, much more room for growth.

Our experience with ISO/RTO demand response programs. As I indicated, we've bid into three different ISO markets. We bid capacity, we bid ancillary services, and we've participated in the energy markets.

Our reliability-based emergency demand response resources help system operators avoid blackouts. Our price participation helps mitigate high wholesale prices, and the ancillary service participation helps system operators respond to system contingencies.

We were the first provider in PJM to participate in the demand response in PJM's synchronous reserves market, and we are an active participant in ISO New England's demand response reserves pilot.

On behalf of a number of our more flexible clients, we actively participate with their load in the day-ahead and real time energy markets. In 2006 alone, we responded to over 50 demand response events, and we are also, as I indicated, active in bilateral markets with vertically integrated utilities, and have found that our value proposition there is particularly appealing because vertically integrated utilities still have responsibility for the entire value chain.

But there are some distinct challenges there. So what is working well now? First of all, the capacity needs in the United States are growing, and there's increasing recognition that demand response, while not a magic bullet or a panacea, can respond very well to some of these capacity challenges for both peak and operating reserves.

As prior speakers indicated and FERC's State of the Market showed, last year our electric consumption, kilowatt-hour electric consumption in the United States was relatively flat, down just a tiny bit.

Yet in many zones, many RTOs, we were looking at very substantial peak demand growth. California, ten percent growth; PJM eight; New York, five percent. Texas also up significantly. Demand response is an ideal solution to this trend. Lower capacity factors are perfect opportunities for demand response to participate.

Connecticut, we've seen, has been, and others who have remarked on it, has been a particularly compelling success story. In the last four years, their amount of demand response has increased sixfold.

They've gone from one of the most difficult pockets in the country to meet the reliability needs of that zone and that state, to actually being in okay shape now with the emergence of what is now 506 megawatts of real-time dispatchable demand response that's available to the system operators as need be.

As of March 30th, another positive event is demand response is increasingly recognized as not in competition with energy efficiency. We've seen a lot of complimentary nature between demand response and energy efficiency, and many of our clients are moving more that way.

Status of coordination between retail and wholesale. We ought to be frank. There's much work that remains. We're encouraged by FERC and NARUC's joint formation of committees to take on this challenge. But there is lots to be done to get the state and federal programs working together.

New technologies, not too different than Dr. Neenan's comments, the technologies are right there right now to get a lot more demand response into the market. We don't need to wait for new technologies.

On behalf of InterNOC, I thank you for your time, and look forward to responding to any questions you might have.

CHAIRMAN KELLIHER: Thank you. I'll now recognize Jack McGowan, President and CEO of Energy Control, Inc. You are also chairman of Gridwise Architecture Council.

MR. McGOWAN: Yes, good morning. Thank you for the opportunity to be here today. As stated, I'm chairman of the Gridwise Architecture Council and I'm here also as CEO of Energy Control to discuss the idea of interoperability, which primarily addresses the final question posed for this panel.

Interoperability is an information technology characteristic of equipment and systems, and the word itself can be daunting. That is why the policy team of the Gridwise Architecture Council has put a great deal of effort into developing a draft document that's been circulated here today, with the goal of defining the term and its importance to simplify this discussion.

I would ask you to reflect on the first time that someone explained to you how the Internet works. It was very likely confusing and full of technical jargon, and seemed quite foreign.

Yet we all have come to understand at least conceptually how the Internet works, and more importantly how it has changed our lives and transformed the way we carry out many activities.

The Internet is nothing more than interoperable collection of computer networks that facilitate communication, and deliver massive amounts of information. It can offer access to a wide variety of products and services.

That is interoperability. The Gridwise Architecture Council believes that interoperability can be applied to electricity, and have the same transformational impact on the U.S. electric grid that the Internet has had on business education and entertainment.

The growth and success that has been seen with demand response is an early indication that interoperability can have the impact that we foresee. Demand response leverages interoperability in a limited way, with a very specific goal, curtailment.

That point may require some further explanation, because I'm not saying demand response is flawed in any way. Rather, I'm saying that expanding the breadth and functionality that is currently being implemented with demand response would lead to more expanded benefits for the electric system and the electric user, while at the same time creating far-reaching business opportunities in the energy arena.

So you might ask what would this look like? Well, consider that we now can see our telephone as a camera, a computer for e-mail, software applications and music player, etcetera.

That is possible because an interoperable system has been created that leverages smart devices. The phone is simply an interface device, and the telecommunications infrastructure is the system.

In much the same way, an interoperable electric system would make it possible to enable demand response, but would also make it possible to do much more than curtailment.

Leveraging an interoperable smart electric grid was also open an dramatic opportunity for proactive strategies that make it possible to reshape demand curves, based upon operational and economic data.

From an operational perspective, predicting load curves based upon past performance, weather and other factors would make it possible for such a grid to leverage interoperability from end to end within the electric system, to enact changes in the way that users consume power.

This would relieve stress points on a grid and result in energy efficiency. From an economic perspective, consumers in all sectors would, for the first time, be able to use power, the power of smart systems, to choose to shape the amount of energy they consume, based upon the value that consuming that energy produces.

The net effect of interoperability would be to create an e-Bay style marketplace for electricity, which enables utilities to utilize the demand that consumers represent, along with the price signals and other economic data to change the fundamental characteristics of the electricity transaction.

The system is designed for power to flow one way and money to flow the other way when the bill is paid. Demand response is an exciting example of how customers and utilities are willing to change the dynamics of that transaction.

As we all know, it's critical to enable these types of strategies, in the face of recent predictions, that suggest the U.S. electricity industry will invest $300 billion in T&D facilities, including advanced meters, over the next decade, and $400 billion in new power plants over the next 25 years.

These investments are driven by estimates that the electric demand in the country will increase 40 percent over the next 20 years. Demand response is a valuable tool that can be dramatically expanded by using interoperability and a smart electric grid, to create smart strategies that utilize technology to enhance system reliability.

Interoperability can hedge against how quickly the investment infrastructure must be made. However, if we start now, we can build interoperability principles and capabilities into the investments when they are made and hasten the improvements and reliability costs, innovation and value that interoperability can deliver.

This is a key focus of this week here in Washington. If we do not, more resources will be wasted, more assets stranded and reliability threatened by our failure to move ahead with grid modernization and interoperability. Thank you.

CHAIRMAN KELLIHER: Thank you very much. I'd now like to recognize Mr. Robert Pratt, Program Manager of Gridwise at Pacific Northwest National Laboratory.

MR. PRATT: FERC Commissioners, conference guests, thank you for the invitation. Smart grid technology is essentially a two-way communication, and intelligence at all levels of the power grid.

Smart grid is poised to deliver demand response, and the control of other distributed resources like distributed generation and storage, and deliver these in an integration fashion into the everyday operation of the power grid, reducing costs for new infrastructure, mitigating peak wholesale prices and increasing reliability.

I would add that the SmartGrid can also be leveraged to transform the grid into a national asset for our sustainable energy future. I'll address that at the conclusion of my remarks.

We've been conducting a project in the Pacific Northwest, Coal Oil from the Gridwise Demonstration. It's on the Olympic Peninsula in Yakima, Washington and Gresham, Oregon. It's a partnership of the U.S. DOE, the Bonneville Power Administration, Pacificorp, Portland General Electric, IBM, Slotland County PUD No. 1, the City of Port Angeles and Whirlpool Corporation.

This is small-scale pilot project that attempts to very aggressively illustrate that the key characteristics of SmartGrid technology integrates a wide variety of resources deployed among residential, commercial and institutional consumers, with a moment-by-moment operation of the power grid, and leverages those resources to bring about multiple benefits at all levels of the grid, including wholesale markets, transmission congestion, relief of distribution pinchpoints and ancillary services.

There are approximately 200 residential consumers that have been offered a choice to shift from their normal fixed price contracts to some type of a time-differentiated contract.

They adjust their use accordingly to lower their power bills. They respond to either their choice of a time of use, critical peak price or a five minute real time price.

About half of those people chose to pursue real-time prices because of the greater savings opportunity that was presented to them to do so. Home energy management automation technology allowed these customers to fully automate their response to these price signals, adjust their consumption and set their preferences for their relative desire for economy or comfort, and change or override those at any time.

The Invinca system is a smart meter or gateway between broadband service and the home computer, a smart thermostat, a water heater, load control module, all communicating wirelessly. Consumers use their home computer or their Internet connections to program their responsiveness.

The core of the project is a local substation level retail market that superimposes the cost of wholesale electricity and transmission congestion. The local retail market closes every five minutes to handle the distribution constraint, although that is an artificial constraint at this point.

The same market signaling mechanisms are used to aggregate the response of a commercial building, a backup generator, a microturbine and a municipal water pumping system.

We've observed some very remarkable capabilities of this two-way based communication based demand management network. It can cap net demand at an arbitrary level with 16 percent less than the normal peak demand, and do this for days on end.

That's real capital cost savings when you're talking about a $10 million substation that an easily synchronous thermostatically-controlled load to follow the need of the grid for regulation.

Demand resources easily respond over the short term, because the excursions from the normal set points are so small that there's minimal if any discomfort and the market closing costs to obtain this kind of response are very low.

As a consequence, the implication is that demand can provide ancillary services very analogous to regulation and likely do so at costs far lower than power plants charge to ramp up and down.

We also have a network of grid-friendly appliances that autonomously, on their own, detect under frequency events and shed load for up to a few minutes. We have retrofitted water heaters and new clothes dryers from Whirlpool, and no one noticed, even though we've shed load hundreds of times over the course of the last year.

This is an ancillary service that can displace spinning reserves and increase reliability, and it can react within a half of a second much faster than power plants. It also delays and randomizes the restoration to avoid shocking the grid and collecting per load pickup after an outage.

Mass-produced appliances in the residential sector alone represent about 20 percent of the demand. So this a very low-cost inexpensive safety net for the power grid, since no communications are required to provide this simple function.

It may be self-evident that no one's going to notice a water heater being off for a minute or two, but a clothes dryer that Whirlpool provides turns off only its heating element. It keeps the controls active. The drum is tumbling and that's why nobody notices.

Whirlpool also has added a demand response function, since we were communicating with these dryers to measure their performance. Whirlpool displays a high price warning when we hit it with a signal on a tap, and the user is required to push the buttons twice to get the machine to start instead of once. It's a prompt to just look and say I'm paying a lot for this load of clothes.

Finally, looking to the future. It's increasingly apparent that the utility industry and policymakers are beginning to focus on energy efficiency and renewables, in light of the growing concern about climate change.

Congress is actually considering policy options by capping trades for carbon, national renewable portfolio standards, energy efficiency portfolio standards and so forth.

We can have a grid that is more efficient, less expensive and cleaner if we extend the capabilities of the two-way demand management network as the basis for controlling, measuring and motivating our future sustainable energy system. Thank you.

CHAIRMAN KELLIHER: Thank you, Mr. Pratt. I'd like to now recognize Dan Sharplin, President and Chief Executive Officer with Site Controls, Inc.

MR. SHARPLIN: Thanks for having me. As a newcomer to the business, I've been at this for four years since we founded Site Control, and coming from the technology side of the business, not the energy side of the business.

We have a slightly different perspective on the pace of change and what we can see happening out there. In the last 12 months, we've seen increasing strides led by FERC. Some of the FERC's efforts, like the effort David led last year regarding demand response, is taking hold, creating real benefits as the technologies emerge.

To meet these needs in the market, I have reworked my talking points a little bit, because most of the stuff that I wanted to say has been said already. But I wanted to respond to some of the things we've heard today, and I really wanted to start with what Commissioner Moeller said with respect to the shortfall between the potential for demand response and the realization that's been out there and the frustration around that.

We look at it and then we think we see a tipping point that's happening here. To Phil's point earlier regarding the technology that's being deployed, something he didn't mention that we're all noticing, a lot of investor interest.

It's now beginning to capitalize these business models and technologies that are creating real opportunities to deploy this technology far and wide. From Site Control's perspective, I'll tell you a little bit about what we do. But I wanted to touch a little bit on the primary concerns that we see.

The first one is our information inefficiencies. This is something you've heard about this morning. The information inefficiencies we see have to do with timing, getting the data to and from the decision-makers in real time or near real time.

The other one is content. The idea of what's in that information packet allows us to act on it. Then lastly, cost. We believe that the telemetry ought to free or near-free, and frankly we think ought to be web-based.

There are transactional inefficiencies, reasonable price and consumption visibility for the consumer, reasonable decision-making implementation tools. It's one thing to know about a situation; it's another thing to be able to cost-effectively and efficiently respond to it.

So some of the technology you've heard about today, we see that as making a big impact. Regulatory and legacy constraints, especially with respect to aggregated loads of less than 200 kilowatts, that's the world in which we live.

Phil's kind of leading the way with 400 kilowatt loads. We're leading the way with 100 kilowatt loads. Frankly, the obstacles with respect to getting real time information cost effectively is one of the key constraints that keep us from scaling more rapidly than we are.

Lastly, one that hasn't been talked about very much is consumer acceptance. This has to be done at acceptable cost and the costs are more than just the financial costs. It's the impact of the business or the impact of the homeowner. Those include the administrative burdens.

A little bit about Site Controls. The key point is that automated near-generation quality demand response is coming on-line today, right now. We are building out a network load management resource base in the traditional hard-to-reach small building market.

The small building market, which we defined as less than 200 kilowatts, accounts for as much as 25 percent of the ISO coincident peak. The new technologies that we're aggregating and deploying create material network load management opportunities with minimal customer inconvenience, including reg up and reg down capabilities, balancing, renewables and automated emergency response.

Following up on what Henry and Glen said in this morning's conference, what we're building in intelligent load management is a real time validated two-way network, with all sites communicating with the data center in real time, in five minute intervals.

We have flexible aggregation. We're able to aggregate those loads into particular geographies, and make them responsive. We believe it's a knob, not a switch. We twist it. It's very granular, very localized. It can go deep long, it can go deep short, and its load consequence.

We have demonstrated that with these types of customers, we can do a 50 percent demand reduction with acceptable consequences for four hours. We can do a 20 percent demand reduction for four hours with no discernible impact. Nobody will notice. The key point is that it's dispatchable and verifiable in real time.

We've deployed primarily through an integrated energy and business intelligence product that's gone to 2,000 sites across the country on our network. The customers buy from us because we help them achieve a rapid return on investment from energy, and facilities management, typically a 50 percent return on investment. Thank you.

(Laughter.)

CHAIRMAN KELLIHER: Thank you very much, Mr. Sharplin. Why don't we go with ten minute rounds of questioning? I will give a good bit of my time to staff, but why don't we start with ten minute rounds, and start with Commissioner Wellinghoff?

COMMISSIONER WELLINGHOFF: I'd be happy to do that. Thank you, Mr. Chairman. Rob, if we could start with you. I'm quite excited about some of the information you've provided us in your experiment that you're doing in Washington.

You indicated that demand response can provide ancillary services that cost less than power plants, and I assume do it better in essence. It's doing it quicker, right?

MR. PRATT: That's correct. When I say do it cheaper, that's simply because we found if you want somebody to respond with their thermostat by a degree or two, or five or ten minutes, they don't even get outside that degree or two bound in that five minutes.

So the key difference in demand response and regulation is that a lot of demand response loads have a makeup. There's an upside after you've taken them down, and in a bunch of your restored service, there's an upside.

There needs to be a little bit of thought put into that characteristic as we try to integrate regulation services.

COMMISSIONER WELLINGHOFF: The other side of this is if the demand response is providing these ancillary services and the plants aren't, they're not ramping up and down. They're operating at a more efficient level. Is that correct?

MR. PRATT: That's right. Ramping them up and down is very inefficient.

COMMISSIONER WELLINGHOFF: So what we're doing is it's sort of a double benefit. We're benefitting by lower costs from the demand response, but we're also getting the benefit of having our existing plants operate more efficiently.

MR. PRATT: That's correct.

COMMISSIONER WELLINGHOFF: So I'm interested.

Are we looking at hopefully expanding your pilot into an RTO/ISO area, where we can get more data on this?

MR. PRATT: I'd love to do that.

(Laughter.)

COMMISSIONER WELLINGHOFF: Was this funded by DOE.

MR. PRATT: The primary funding was from the Department of Energy Bonneville and Pullman General Energy. Whirlpool and IBM also contributed a great deal of in-kind effort.

COMMISSIONER WELLINGHOFF: I'd love to get a larger pilot going in an ISO or RTO region. That would be terrific. Dan, if I could move to you, and I appreciate your remarks, and the remarks of all the panel very much.

But if you could talk a little bit more about the cost of telemetry, and how we can get those costs down for these smaller, 100 or 200 kilowatt loads. What needs to be done there to help that?

You say there's some role on the wholesale ISO or RTO level versus the retail level on how they would do that.

MR. SHARPLIN: A primary constraint is that the AMI efforts are not going after this market in any large scale, and the cost to deploy minimal meter with telemetry is not prohibitive but it's darned expensive.

What we have done is we've targeted the customers that already have a wide area network and have broadband to all of their sites. So there is essentially free telemetry available. Now you have to work out the security issues and all that goes with that.

But we've leveraged the wide area networks that already communicate with these sites, and we've put in a clamp-on meter downstream of the utility meter that we operate with. That's pretty inefficient.

When we see meters merging with new devices and the evolution of technologies that would pick those up, that would allow us to talk about the development of the implementation, if we can take it back and haul it back using the TTPIP connection that's already there.

COMMISSIONER WELLINGHOFF: If we could talk a little bit more about the policy interaction between the states and the federal government, and how we need to better coordinate that. I'll start with Phil, but anybody else on the panel that wants to answer the question.

Phil was one who brought up the issue. A lot more coordination wants to be done. If you want to elaborate on that, Phil, and give us an idea of how we can help on our side, the federal side.

MR. GIUDICE: Thanks. I'll be glad to, and I don't have the answer, but it does feel, and I think the earlier panel was speaking about the various initiatives that are going on in various RTOs and ISOs.

They seem a little bit suboptimal to me. They're being done on a region by region, sometimes on a state by state basis, and it's understandably necessary to get all the various parties involved through the various mechanisms.

But I wonder if it might be possible for FERC and NARUC in this new initiative to really set on very bold goals for what they would like to see come out of that, and a very aggressive time line for deliverables and outcomes.

It might include things like, you know, what would be appropriate baseline technology to be put in place here? Instead of every ISO, every RTO, every state trying to make their own interpretation, it might be what kinds of real-time metering and verification or sort of best practice, to sort of implement across a wider group of folks.

There's three or four others. What kind of performance reporting? We spoke to in the past about how we can actually really reliably track and understand how these resources are performing when they're called in terms of events?

It's done understandably at this time, on a very sort of individual utility, individual RTO basis, and perhaps this NARUC/FERC group could come together with a very much stronger set of sort of deliverables, so to speak, and a time table on it and say, you know, we don't --

We need to have another smaller regional kind of effort. We can pull this together on a national basis and say based on the collective thinking of this group, that's the best way to go forward.

COMMISSIONER WELLINGHOFF: Maybe if I could go Chairman Ebert, since you brought to us a specific problem, and kind of comment on this issue of how we can help alleviate the problem that you talked about.

But also in a broader sense, better coordinate the state/federal effort so we can all move forward in a way that we all benefit, and certainly that your constituency, the consumers in Wisconsin, benefit.

DR. EBERT: Yes. Obviously things like we're doing today are of tremendous value, calling attention, and I think as the other panelists talked about the FERC/NARUC collaboration. So I think there are clearly some broader national goals we could pursue.

I would like to just share with this group, part of the experience that we're going through in the Midwest is that we have significant differences among the states as far as the level of demand response and how much they may have been integrated in the state-specific portfolio.

There are some states that have done very little in this area. So I think there is some value and I think there's probably value in two approaches.

One is continued aggressive FERC/NARUC/Congress action, and also making sure that the states are sharing, on a regional basis, sharing amongst ourselves some of the successes. We are in some respects in the Midwest a little bit behind some of the other regions.

As a region, I think there are some really good things happening in individual states. But as a region, I think we're a little bit further behind. We've got a lot of work to do, to have all of our states get caught up.

I think it's probably a balance there. I'm for continued very aggressive FERC and NARUC attention to this question, but also we need to continue to stay focused and roll up our sleeves, and as a region bring us up to sort of on par. But I think there's probably value in both.

COMMISSIONER WELLINGHOFF: Dennis, do you have a comment there?

MR. DERRICKS: Yes, I do. One of the things that would provide value to us as a load-serving entity is to really address resource adequacy.

It's kind of nice thing out there with smart meters, dumb rates. Part of the reason that there are dumb rates is that we haven't completed the wholesale electric pricing design. Again, from my perspective, to have long-term sustainability for demand response is to adequately reflect wholesale prices and retail rates.

Demand response program is based on an energy-only market. It will be different than one that is on a capacity market. The sooner that we can resolve that, the sooner that we can move forward more aggressively with demand response.

COMMISSIONER WELLINGHOFF: Let me follow up on that with you as well, Dennis. Would you also agree that demand response, as Mr. Pratt has indicated, can really play a huge role in all these ancillary services as well, and in fact may do so in a way that would improve the efficiency of our whole generation fleet?

MR. DERRICKS: I believe technology will play a large role in the evolution of demand response. To understand that I think is very important. The bigger picture is making sure that we get the pricing done appropriately, so that we send the right technology and the right pricing for the right customers and our vendors.

COMMISSIONER WELLINGHOFF: Let me just focus in one more time. Pricing won't provide us with ancillary services though, right?

MR. DERRICKS: Pricing is part of the ancillary service market from my perspective.

COMMISSIONER WELLINGHOFF: Thank you, Mr. Chairman.

CHAIRMAN KELLIHER: Commissioner Moeller?

COMMISSIONER MOELLER: Mr. Chairman, another great panel. First, I guess, welcome to my fellow Washington stater, Mr. Pratt. Glad to have you here.

My philosophy on all the demand responses is not altruism. We have to make sure that those who benefit get adequate compensation. The regulatory scheme that the state of Wisconsin has been a leader on makes sure that rewards follow the people who deserve them.

It can't be to a utility or a customer's detriment to play in this market. So in that sense, I guess, we heard really that we have, depending on the situation, we can implement this successfully and largely the industrial format, I presume.

Those are mostly paper companies around Green Bay that are participating. Certainly Alcoa, representatives from the commercial side, are proving that they can do it, and the Gridwise experiment shows that it can be done at the residential level.

I guess I'm interesting going forward from not only this panel, but all day along, thoughts on the barriers. We've proven it's possible. So what are the barriers to more fully implement it, and I guess focusing on the commercial?

First, Dan you've been to visit me, Phil as well.

Can you talk about the markets you participate in, for instance, the 2,000 locations you have? Talk a little bit more about where they are, what works best, if there are things we should know about wholesale markets, that make your business model either more or less workable. Phil as well. Let's start with Dan.

MR. SHARPLIN: For us the 2,000 sites that are on our network are deployed in all 50 states. They are where the people are because we focus primarily on chain stores.

If you take a population map of the United States and lay it out and you look at our map, you see a very similar pattern emerge. We are where the people are. We are where the congestion is.

Our customers buy and deploy our solution enterprise-wide, and they do it for a whole host of reasons. We have one that is buying almost exclusively to reduce their carbon footprint this year.

We see Site Controls customers reduce their carbon footprint by 130 thousand tons of CO2 just from the efficiency savings that come with the installation of the platform. Having deployed the platform first, now working towards okay, how do you enroll that in the demand response programs or ancillary markets and the like?

The constraints are coming out as fast and furious. We've had some wonderful successes, for instance, in San Diego, where the IOU there, SBG&E has been very aggressive in trying to open up this mid-sized commercial building market, because frankly it's all they've got.

They really, really want to develop demand response resources, and this is where it is. They've created all sorts of programs. They really tried to work through the metering issues with us. That's been a great success for us. We're targeting a lot of efforts there.

We're piling a lot of load into San Diego now, and we're using that to validate the whole business model in other markets, where we've tried to work with the ISOs.

We haven't overcome the metering question. While we can clamp on a meter and we can demonstrate it within one or two percent, a lot of these sites don't even have an interval meter in place.

Now we're looking at alternative strategies as to how do we go in and put in place a meter that's acceptable to the ISO. In many cases, the cost just doesn't justify it.

COMMISSIONER MOELLER: So is it the load-serving entity or the ISO that's kind of the driving factor?

MR. SHARPLIN: Yes.

(Laughter.)

COMMISSIONER MOELLER: It all depends?

MR. SHARPLIN: It all depends, yes sir.

COMMISSIONER MOELLER: So you gave an example of utility service territory that's being very amenable. They want to make it happen and it sounds like that's what's going to make the difference, if that's the philosophy, as such, of whoever's in charge to be open and willing to see these services get deployed.

MR. SHARPLIN: They don't have an obligation to make our business case, so we recognize that it's our obligation to prove that the technology is available and that the business model works, that is is viable, new generation quality demand.

Although it's a lot greener than that, there's a lot of other benefits. But it's our obligation to do that. We believe that again, this is mainly a good news story that I'm trying to convey. We see it moving very, very rapidly.

While there are always going to be early adopters and laggards in the market, we're working with the early adopters and we believe the industry will prove it to the laggards, and that there will be acceptance that occurs over the next 12 to 24 months, and that this problem will yield.

But at the ISO level, we have run into that problem, where if the load doesn't qualify, even though we can aggregate it into 100 megawatts, we can control it in real time. We can validate it in real time at five minute intervals. We still can't enroll them.

COMMISSIONER MOELLER: Phil, your thoughts?

MR. GIUDICE: Yes, thanks. Our 578 megawatts really grew four year ago from helping resolve the problems in Southwest Connecticut in particular. The dominant portion of our megawatts is New England. The next most significant chunk is New York, in particular New York City and Long Island, again pockets that are sort of constrained.

Then pockets in PJM, where we see the most interesting sort of economic possibilities, and California, particularly the southern tier of the state, San Diego and so forth. That gives you a sense.

We actually laid a map across the United States as to where are the capacity shortfalls, and/or where are people building capacity and not considering demand response enough as a primary driver, to sort of think about where the markets will probably value demand response the highest.

As on a nationwide basis, as we keep running out of capacity, it sure makes demand response even more attractive. That then drives two things.

One, dollars, as you indicated. We agree. People aren't in this through altruism. They need to be motivated economically for it. Two, which is one of the things we are only beginning to see is some consistency in these programs.

Integration into the market and sort of some stability to these, so that people can start planning and making their business decisions on some kind of a longer-term basis, knowing that this is an ongoing kind of event, not the program of the month club, which I think a lot of the demand response activity in the past had been.

It's not about metering, it's not about technology. To me, it's about money and it's about sort of opening up these markets to these resources.

COMMISSIONER MOELLER: I guess in my last four to five minutes, I'd like the other panelists just to give brief responses, starting with Chairman Ebert, on moving this forward.

DR. EBERT: Thank you, Commissioner Moeller.

COMMISSIONER MOELLER: Two minutes, sorry.

DR. EBERT: Let me be brief, so that the other panelists can answer. I think it's establishing a commitment that this something that we're going to solve, and I think within the context of the states, we now have two working groups, one working directly with MISO and one working within ourselves, to sort of share best practices.

That's certainly part of it. But you know often, we'll use specific time frames, encouraging market participants to respond. Maybe one of the things is what is the next step from the national level that we really need to go and encourage the RTOs to get there by a date specific?

MR. DERRICKS: Simple. Get the prices right. Then I think there's a significant amount of effort that needs to be done on a customer education basis. That is one of the key ingredients, why we have as much demand response as we have. It definitely takes a significant amount of education.

COMMISSIONER MOELLER: Dr. Neenan.

DR. NEENAN: I'll sell my minute to anybody who wants it.

(Laughter.)

DR. NEENAN: I think it's popular to talk about barriers. It's a way of working around the problem. But essentially, we're looking for a problem where there isn't one. When we have the courage to simply start asking customers are they interested in working with us, the problem will go away.

In the meantime, we're obsessing about technology, or things that are supposed to enable price responses that have worked very well in isolated, but very successful situations for 30 years.

Perhaps it's time to ask customers and face them and figure out how to explain it to them, an effort which I'm totally unqualified for, by the way.

MR. BROCKWAY: It is about money, of course, but I would emphasize that we're not in a demand response market to make -- we're in business to make aluminum. But we want to participate in the market to moderate the prices, so we can continue to make aluminum.

When we speak about barriers, and I think everybody's touched on it, probably so much a barrier but a mind set or an education. This is picking on ourselves. We need to change the mind set internally, for we must make our product at all costs all the time, 24 hours a day. Let's make decisions on when we make the product.

So if today you said to an operating plant manager you're going to reduce your load by 50 megawatts for three hours, they're going to throw thing at you. We need to change that mind set and that incentive from top down to say no, it's okay to make that decision, based on economics of course.

We are about making money. That's an internal barrier that we are overcoming. We are working on that. It will take time to get there, and there's probably a barrier on the operator's side. I'm only assuming this. I don't know this. It's time to reduce load or pick up generation.

Their mind set is pick up generation. So look at "Oh, we can reduce load as an option as well."

COMMISSIONER MOELLER: Mr. Chairman, can I get a couple of more minutes to get the last couple of responses?

CHAIRMAN KELLIHER: Yes.

COMMISSIONER MOELLER: Mr. McGowan.

MR. McGOWAN: Thank you. I wanted to reinforce another aspect of this whole dialogue, and it may seem inappropriate to talk about expanding the potential for demand response in light of your earlier comment, which is that it hasn't been perhaps implemented as much as we would like to see.

But the idea behind interoperability is also communication. The notion so far with demand response has to be to react to supply events, with technology as the solution. The idea that we have with interoperability is that we can be proactive and in fact we can anticipate it and we can leverage the intelligence with devices to allow us to anticipate events and react accordingly.

We're working on a DOE fund demonstration project in New Mexico right now, which is going to allow the utility for the first time to see not just load as an aggregate, but to actually begin to start understanding how customers, in their individual use patterns, actually consume power and to use technology to change those patterns based on the price signals and the value that can be generated by changing their consumption patterns.

MR. PRATT: I think a key issue is that utilities need a rate of return for investment for SmartGrid investments, that's if we're going to get a rate of return on infrastructure.

That's an essential ingredient for them to move forward. I don't think the PUCs are going to let them do that, if we leave the residential sector behind.

To the point earlier, residential is big. It's mass-produced, and that mass-produced is really where interoperability comes in that Jack was talking about. There's a switch on every electrical device already. All we need to do is get the signals to those devices and coordinate them using the Internet.

PCs, energy management systems and industrial and commercial buildings, and you've got demand response just automatically. Business as usual for everybody.

COMMISSIONER MOELLER: Thanks to all of you. Another great panel.

CHAIRMAN KELLIHER: I just have a few questions and I'll turn to staff. I'd like to follow up on something that Mr. Derricks said.

There was an implication I want to follow up on. You were talking about energy-only markets and capacity markets. Are you suggesting that the potential of demand response is greater in the energy-only markets?

MR. DERRICKS: No. I don't think I was implying that.

CHAIRMAN KELLIHER: You're just saying it's different, not better.

MR. DERRICKS: It is different. I think an energy-only market, at least from our company's perspective, we truly believe that an energy-only market theoretically can work. I'm not exactly sure that it works in today's environment, based upon where we are today.

I think a capacity market, and again I talked about our interruptible program. I think a capacity market lines up very well with our interruptible program, again reflecting a demand credit, reflecting the avoided cost of the utility buying or building capacity. That can be lined up very well.

At the same token, to the degree that we get to an energy-only market, either now or later, we will have to design programs that reflect that marketplace, and just work with customers to try and match wholesale prices to their retail needs.

CHAIRMAN KELLIHER: Thank you. I just wanted to follow up with Dan. We are trying to come up with federal approaches on demand response, which are consistent with state approaches. They don't have to be exactly the same, but they can't be contradictory really.

It's probably harder in the multi-state organized markets than it is in New York or California, particularly if there's some level of disagreement among state regulators in that region.

I just wanted to get some sense as to how high do you think the level of agreement is in both PJM and MISO on certain approaches, on demand response? Are there sharp differences? Are there some differences? Just some sense of that.

DR. EBERT: I don't have a strong sense within the PJM market. My general sense is that there could be closer coordination and collaboration between the two RTOs as a general matter, and I would say that probably also would apply for demand response.

But I don't have a lot of specifics as to where PJM is. I do think that we -- I guess in order to answer your question, is there a specific area you're concerned about?

CHAIRMAN KELLIHER: Whether a state has opened their retail markets, or whether they have a traditional regulated retail market, or whether they have a competitive retail market, and if so, if state regulators have completely different attitudes on demand response, or is it not that sharp?

DR. EBERT: My observation is that there are some clear differences among the MISO states, depending on whether you're traditional regulation or you're retail choice, absolutely.

If you look at the states within MISO that have significant demand response programs, they are traditional regulated states. Minnesota, Iowa and Wisconsin. Does that mean -- is that a statement on who's better or not? No. But I think it is just a matter of how the policies have developed in these particular states.

I do think we need to, as a group, really move much more aggressively much faster. I think there in Minnesota, Iowa and Wisconsin have some valuable experience. That's not to say that in the case of Wisconsin, some of these tools are 20 years old, 25 years old.

We also need to internally take a look at how these tools are working with our utilities in our states, to make sure that we have designed the right tools for the wholesale market.

That's something we need to do internally, and we are doing that. But then also as a region, to make sure that we are working through the retail choice, non-retail choice tensions that exist, to make sure that we are fully embracing and aggressively embracing demand response.

CHAIRMAN KELLIHER: Thanks. That's another way of complexity, to have a regional approach. That assumes varying state approaches and retail competition and retail markets.

DR. EBERT: Absolutely.

CHAIRMAN KELLIHER: It's not impossible. Those are really the only questions I had, and I hope to learn more from staff. Then my colleagues can have some more time at the end. Well, we have 12 minutes.

Why don't we start off with my colleagues? Do you have any additional questions before we get to staff? No. Okay, staff. You have until 12:30.

MR. KATHAN: I want to return to the question that half the panel was talking about, technology and issues of telemetry and metering.

Ultimately, what is the solution I guess is the major question, but more fundamentally, since advanced metering is primarily a retail issue, trying to focus on what should be the ISO's policies?

What should they be doing in order to make it such that it's interruptible or the information can be observable, such that it can help with operations. I open that up to anyone on the panel.

MR. PRATT: I'll take a stab at that. I think one of the keys is we need bids, not baseline systems is the buzzword I'll use for this.

In our project, we were able to get quite a good bit of information about what people would have consumed in the absence of demand response, because they're basically asked to bid every five minutes saying what they would consume at a normal price.

Then in the iteration of the market and the closing of the market you find out what they really are willing to buy at the closing price.

So by giving them a rate and letting them respond to that and suffer the consequences, positive or negative, then using that bid information, we got the M&V that we really wanted without doing a whole lot of submetering.

My guts tell me there's an essence of something important there that can make this really a lot cheaper and a lot more transparent.

It comes down to two basic factors. One is security. The other is deployment. The question is how do you haul back the information? Do you do it via proprietary network, or do you do it across an existing Internet connection?

Our belief is an existing Internet connection should be more than adequate, especially in the world in which we live. When we're talking about commercial buildings, they're moving every single credit card transaction and all their financial data and everything else across the network. At least the customer wouldn't mind having their utility information go across that also.

So the security issue that we run into sometimes, that we think that ought to yield at some point in the near future, the other one is just deployment, the ability to have meters deployed even when we're willing to pay for them, by the way, and we're willing to pay for the utility to go install them.

There's a long fuse there to actually get those deployed on any large scale.

MR. McGOWAN: In addition to that, the other things that comes into play here is leveraging existing technology.

It goes back to the idea that you want to be able to have utilities get a rate of return on the investment that's made, and when they look at buying new equipment and investing in infrastructure, that the infrastructure be deployed in a way that it is able to communicate effectively throughout the network.

I also think it's critical to take advantage of the infrastructure that's in place, from a technology point of view, in buildings and other structures.

I agree that you can't leave the residential sector behind, but it's important to recognize that there's been a big investment made on the customer's side of the meter, in automation and in technology that can be very valuable.

For example, I have a colleague who purchased power in a deregulated market, where the supplier had difficulty getting access to meter data.

That individual provides information from a building automation system to that supplier on a day-to-day basis, on which they are billed, because they're leveraging infrastructure and technology that's already in place in the buildings.

There's a lot of technology in place that can be utilized to further this effort towards demand response and beyond demand response.

MR. KATHAN: I had one other question. Dr. Neenan, and I wanted to give you a chance to elaborate a little bit more on some of your comments about the direct bidding programs turnabout, and your views on it. Could you describe a little more what you're meaning?

DR. NEENAN: I may have exhausted all I know.

(Laughter.)

DR. NEENAN: I don't see it as a philosophical turnabout. I think if you read what some of us were thinking five or six years ago, we recognized that there were some inherent problems with bidding that have to do with things that cause us to wake up like welfare, you'll pay us to measure things like this.

But they have the very pragmatic notion, you're paying somebody to do something that they should do naturally in their own self-interest. I believe if you look at the time that these programs went through PJM and the New York and ISO New England all struggled with us, when it came forth to you it was part of our transition.

"We'll do it for a while." A while won't become ever if we don't find a way to get customers involved in the market. I can't see how ISOs can accommodate tens of millions of customers bidding everyday and what that has to do with an efficient market.

This is the demand side of the market. We've spent millions, tens of millions or hundreds of millions of dollars, and enormous intellectual capital creating a wholesale, which forgot all about the retail.

It's harder to be honest when you're writing a software program. To solve a non-linear programming problem, it's a snap, compared to trying to tell customers, who for 50 or 100 years we've told don't worry. The price is the same all the time, we'll take care of you, "Now it's on you."

Well, that's what's got to happen. To the extent that FERC can help with that, I'm not familiar. I don't want to get into the interagency issues, but I think you've done a lot. I think you've demonstrated or sort of confirmed maybe what people thought was true anyway.

People will respond to price of electricity, just like they do any other good. Now the issue is how do you get these prices in front of them, and how are those prices meaningful. I think that's got to involve a variety of methods, because we have different market models.

People are trying single market models all the way through even centrally organized, highly structured markets. So there's going to be different ways and different methods. It's going to involve coordination and linkage. We're going to have to work state regulators and stakeholders to figure out what works in each area.

The answer is not us; it's customers. How do you get customers interested?

COMMISSIONER KELLY: Mr. Giudice, was it you who said you had aggregated 100 megawatts or so and couldn't get it into an RTO, somebody on the panel?

MR. SHARPLIN: He can bid his in.

MR. GIUDICE: We're okay with getting our megawatts in.

COMMISSIONER KELLY: Could you be more specific? Is it one or more RTOs? Is there a reason given? Lay out the barriers in more detail.

MR. SHARPLIN: I think it's probably helpful if I actually got my team that's working on that to write up a little case summary and send it along. So we can do that on the backside of the meeting.

In essence, it goes to a lack of acceptance of our, I think it's called, a Class B or a Class 2 meter, a clamp-on meter, that basically we can calibrate within about one and a half percent of the utility meter.

But the lack of interval data from the utility meters, it's not even available there, is what appears to be preventing us for monetizing those loads into the ISO. Is it okay if I don't talk about the particular ISO?

COMMISSIONER KELLY: Sure. But your meter is accurate within what percent did you say?

MR. SHARPLIN: About one and a half percent.

COMMISSIONER KELLY: Is that considered not good enough?

MR. SHARPLIN: That's a barrier we live with everyday. That is it.

COMMISSIONER KELLY: Thank you.

CHAIRMAN KELLIHER: Commissioner Moeller?

COMMISSIONER MOELLER: I just wanted to mention to Mr. Pratt by endorsing the virtues of a bid-based system, I just want you to know back in our home state of Washington, there will be some people who think you're a very dangerous man.

MR. PRATT: I'm well aware of that.

(Laughter.)

MR. PRATT: I'll wear a helmet when I say that.

COMMISSIONER MOELLER: Again, thanks for being here.

CHAIRMAN KELLIHER: Any other questions?

(No response.)

CHAIRMAN KELLIHER: Well, I think we'll take a break now. I would like to point out to the panelists that lunch is being provided, courtesy of Commissioner Wellinghoff upstairs.

Staff, not just this panel, the earlier panels, the later panels, staff can help can help escort you up to the 11th floor. Thank you for your help, and thank this panel for your help very much.

(Whereupon, at 12:25 p.m., a luncheon recess was taken.)

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

1:45 p.m.

COMMISSIONER WELLINGHOFF: If we could begin. All take your seats please. I'll be taking over the chairmanship for this first panel here. He has a meeting he has to be at, but he indicated he would come back for the second panel.

I do appreciate all the efforts that were put in by our panelists this morning. I know we got some great information. As we heard earlier today, there are several initiatives underway to integrate demand resources into these wholesale markets.

The Commission has also determined, though, in our recent Order 890, that demand response must be evaluated on a comparable basis, to services provided by generation resources and meeting mandatory reliability standards, providing ancillary services in the planning and expansion of transmission grids.

With these initiatives underway around the country to bring demand resources into wholesale markets and into the operation of the transmission system, we need to know how to measure demand resources, and how to determine that we can rely on them today and tomorrow, to make the reliability and other functions that transmission system operators pay them to perform.

Therefore, I look forward to this panel's recommendations on best practices, and measuring the impact of demand resources in market and transmission system operations, and what our next steps should be.

We're going to hear first this afternoon from Jeff Schlegel, who's an independent consultant with Schlegel and Associates. Jeff gets sort of a privileged position. He's going to get ten minutes to do a Power presentation. Then we'll go back to our five minutes per panelist.

From there then, we'll have questions from the Commissioners. I believe Commissioner Kelly may be joining us as well. Then we'll see if we have time left for staff questions as well. Jeff, if you could go ahead and proceed please.

MR. SCHLEGEL: Thank you, good afternoon. Thanks for the opportunity to participate today and also for the lunch. I'm an independent consultant from Tucson, Arizona, and I work primarily in three states, Arizona, Connecticut and Massachusetts.

Today, my comments are my own and I'm not here on behalf of any client. Since I work in both the west and east, I'm familiar with the range of opportunities for and barriers to demand resources in a variety of wholesale and retail environments and regulatory models.

Today, I've been asked to present a brief primer on the mission and evaluation of demand resources from retail rate barrier-funded programs to incentive-based and price-based demand response of wholesale markets.

(Slide.)

MR. SCHLEGEL: As part of my assignment, I'll be covering several aspects of retail-wholesale interface as they relate to demand resource, M&V.

(Slide.)

MR. SCHLEGEL: As you know, there are a wide variety of demand resources with fundamentally different characteristics, from retail ratepayer funded energy efficiency programs providing both energy savings and peak demand reductions, to various forms of incentive-based and rate-based demand response, which generally perform and are apt to perform over shorter time periods.

It's this diversity of demand resources -- next slide.

(Slide.)

MR. SCHLEGEL: That leads us to a variety of measurements and verification and evaluation approaches, as well as planning approaches, which are based on first, the objectives, what we're trying to do.

The objectives of the demand response program are initiatives, the fundamental characteristics of the resource and the specific measures being installed.

The timing of the impacts, not only whether they're short- or long-term, but whether they're associated with peak or some other critical time period.

The issues of the M&V results, whether they're used for cost allocation for capacity markets and capacity decisions, or resource or transmission planning.

Finally, the perspectives of the stakeholders and market participants. The M&V approaches vary primarily because the demand resources themselves vary fundamentally, based on those factors.

Therefore, a one-size-fits-all M&V approach or requirement will not address the diversity of demand resources. I want to be clear here. I do support very much increased consistency and compatibility, but we should not underestimate the challenges to get there.

By the way, the diversity of demand resources is a good thing, even if it makes measurements challenging.

(Slide.)

MR. SCHLEGEL: With all that said, I want to highlight a few common approaches or common components for demand resources M&V. There are three common components that all M&V have for demand resources.

First, the measured performance of the demand resource measure or installation in its installed condition, generally determined through metering or data analysis or site measurements, or proxy measurements, or analysis of representative samples, or other measured data and techniques. That's the first part.

Second, the installed condition performances compared to the baseline condition, what the performance would be without the measure. Then finally that is specified for some defined time, whether it's system peak, a demand responsive event on peak energy hours, or defined performance hours, which could be short-term, annual or cumulative impacts.

The largest determinant of the level of energy savings and demand reduction is what is actually installed. Therefore, an account or verification of measured installation is important.

(Slide.)

MR. SCHLEGEL: In demand resource M&V, establishing the customer baseline is key. The baseline represents what the customer load would have done in the absence of the program or event. In this case of demand response, the red line shows the actual load and the reduction in load during the R event.

The blue line shows the customer baseline. There are several methods for determining the customer baseline and sometimes the baseline needs to be adjusted, such as for whether sensitive loads during peak periods and one of the other speakers, I think, is going to cover baselines in more detail, so I'm going to move on.

(Slide.)

MR. SCHLEGEL: In terms of the evaluation of energy efficiency and retail programs, again, making the bridge between wholesale and retail markets here.

Generally, the evaluation is based on the analysis of metered and billing data, and other site measurements, and is primarily focused on both energy saving and capacity or demand reduction that lead to capacity reductions.

Many states do routine systematic M&V and they document their M&V in their evaluation work in a technical reference manual or a similar document that contains key impact factors and impact value.

The reference manual is systematically updated and refined, using the evaluation data and the evaluation results, so that the refined values then are used in planning in basically a continuous feedback or continuous improvement process.

This is a very critical point. People pick up that reference manual at a point in time, and it looks like values and paper are on your screen.

But what's in there is the results of decades, in some cases, of M&V studies that are summarized and used to document what has been achieved in these programs, and then to use so that the forecast can be achieved.

Behind each one of the reference manuals are piles of reports of past studies.

(Slide.)

MR. SCHLEGEL: Here is an example of the result. This slide shows the performance of a diversified state for a retail energy efficient program over a five-year period. The blue bars show the plan or the goal value. The maroon bars show the actual or evaluated value.

You can see that the gaps narrow over time, and that for four of the five years, the actual performance is greater than the planned performance, and in one year it's almost identical. It's just slightly less.

You can also see that the performance in this portfolio is much like the diversified investment portfolio. The performance of any one installation may vary.

The performance of any one program may vary, but the performance of the diverse portfolio is just that, diversified. So that it is reliable and can be forecasted. Next.

(Slide.)

MR. SCHLEGEL: Another topic that the Commissioners asked to be covered in the panel, energy efficiency M&V. Is it applicable to wholesale markets? To address this question, I would say yes.

Energy efficiency M&V is applicable to wholesale markets, such that M&V provides reliable systematic measurement of energy efficiency, measure impact and customer baseline.

It's certainly appropriate for the energy efficiency resources, obviously. Many of the M&V approaches and M&V techniques can be and are being used for other types of demand resources. In fact, the statement that energy efficiency and demand response can and should be complimentary applies not only to the programs and the initiatives, but also applies to the M&V as well.

However, addressing the timing, i.e., when the retail versus the wholesale performance periods are, that can be challenging and it's not necessarily a perfect match, as the next slide shows.

(Slide.)

MR. SCHLEGEL: This slide compares the resource valuation of demand resources. The left-hand side of the table lists retail programs and summarizes how they are valued or monetized in physical units, monetized and economic units.

That system generally uses avoided costs that document capacity benefits, energy benefits, T&D capacity benefits, and to do so not only in short-term annual periods, but also cumulatively and over the life of the measures.

The right-hand side of the table shows basically a summary of ISO/RTO programs, and how those generally approach valuation. Then you have demand response events, which tend to be short-term, and for which the timing is unknown in advance.

You have the forward capacity market in New England and being developed in other areas, where there are specified performance hours for on-peak, critical peak and seasonal peak hours, reported in megawatt hours, and you have high prices or pricing events.

Again, the timing is unknown in advance. There's some initiatives going on at FERC where transmission planning that Commissioner Wellinghoff mentioned in his introduction.

Generally, the evaluation is over a shorter time period. If you take any one of these roads, you can clearly see that the valuating of demand resources has not matched up all that well between the retail and the wholesale market and market rules.

There have been some improvements in recent years. For example, the avoided costs for retail programs in New England are being determined based on wholesale energy and capacity market prices.

Three years ago, the New England states moved to a system where their retail avoided costs would be based on wholesale markets. Those avoided costs are now in a second round of estimating those values and determining those values for the future.

But this has required significant work to revise the impact values for measures to line up with the performance period that the ISO and RTOs designate for performance hours. This is not trivial.

Imagine again that all that research that was done in that protocol, the reference manual. In the New England states, that was based on the peak seller hour for the last couple of years.

Now we have several different types of representations of peak in the forward capacity market and in other systems, all that are different than the single peak hour.

So if your research is all based on measuring something at a certain time and now you have a different construct of performance hours, you now have to do new research, which adds to the cost, or you need to somehow or another transfer the research, a knowledge base that you have to this new construct.

So it would really help to better line up when resources are important and the performance periods under which resources are valued. That's a very important item that's generally overlooked.

(Slide.)

MR. SCHLEGEL: Strict M&V requirements can be a barrier to entry for demand resources. They can be a barrier for entry in two ways. In one way, they can just cost more to even get to the table, in terms of getting a demand resource into the market.

In another way, they can limit the type of demand resources that you get into the market. Either the size of the demand resources or the nature and characteristics of the demand resources and indeed the costs.

M&V is a cost after all, and it's often a significant cost for demand resources. The cost of M&V can be between three percent on the low end up to about eight percent on the high end, which is a non-trivial amount of money for demand resources.

Some M&V requirements may not be relevant for demand resources. In some cases, the ISO and RTOs who generally have an experience base or knowledge base dealing with generation and transmission, are not necessarily familiar with demand resources, and M&V practices associated with those resources.

It's simply not necessary to meter the output of each and every demand resources, as one would a 200 megawatt power plant. The construct for demand resources M&V is different than the construct for other types of measurement that ISO and RTO systems are familiar with.

(Slide.)

MR. SCHLEGEL: Increased consistency in M&V would help consistencies across ISOs and RTOs, which I think is something that FERC can directly address, as well as across types of demand resources. Consistency between retail program requirements and wholesale market rules is another area.

For example, the performance periods. The timing is one where we could have an improvement there. The time periods for valuation, the terminology and the common platform for M&V standards and protocols.

Again, I think the platform is important, but we won't get necessarily to uniformity, as my next slide shows.

(Slide.)

MR. SCHLEGEL: M&V standards should -- we should move towards increased consistency, and the standards should be comparable but not uniform. It's the characteristics of demand resources themselves that are different than supply, and that vary across demand resources that drive the flexibility that's needed for demand resource M&V.

So we need clear, appropriate and flexible M&V standards that result in reasonably comparable reliability, and when I say "reliability," consider both cost allocation, which many ISO or RTOs and market participants focus on, or are obsessed with.

It's about the money versus electric system reliability. Those are two different constructs for reliability. The national and regional efforts should consider multiple purposes for retail, wholesale and environmental.

Today, much of the focus has been on short-term or short period demand response for capacity reserves, emergencies and periods of high prices. However, in other rooms throughout the country, people are working on reducing both peak demand and energy use substantially, to reduce greenhouse gas emissions, for example, that cause global warming.

We need to look ahead not only to our current needs but to our future needs as well. Thank you.

COMMISSIONER WELLINGHOFF: Thank you, Jeff, for that primer. I appreciate it very much. Next, we'll have David Nevius, the Senior Vice President with NERC. David?

MR. NEVIUS: Thank you for the invitation. I trust that those around the table know who NERC is from past experience, and more recent experience.

The Commission's regulations provide that the Electric Reliability Organization or the ERO will conduct assessment of reliability and adequacy of the bulk power system and report our findings to the Commission, the Secretary of Energy and others.

We do this annually, seasonally and more frequently if we're so ordered. The first such report out of the Electric Reliability Organization was NERC's 2006 Long-Term Reliability Assessment.

The first one was the ERO, but it was the 36th annual assessment conducted and done by NERC. I wasn't around for all oif them, but I've been around for many of them. We also filed in October of last year the long-term assessment; in November, our winter assessment, which we'll be filing with the Commission and others. Our summer assessment about May 15th. In October of this year, another long-term assessment.

Each of these reports documents the amount of peak demand reduction expected through two specific types of direct demand response programs. One we call direct control load management, and the other, interruptible demand.

These programs directly empower system operators to interrupt load or require it to be interrupted by the customer to support operational reliability requirements.

Combined, these programs represent about two and a half percent of the U.S. summer peak demand or 20,000 megawatts, about two and a half percent of the winter peak demand in Canada or about 2,500 megawatts.

New or expanded demand response programs and initiatives, including peak demand pricing, energy efficiency standards improvements, have the potential to further reduce peak demands. But they depend on customer decisions, and we would refer to them as indirect programs.

Just a quick definition that we use for direct control load management. It's that amount of customer demand that can be interrupted at the time of the seasonal peak, by direct control of the system operator, by interrupting power supply to individual appliances or equipment on customer premises.

For example, the utility has a program they sign customers up that allows the utility to interrupt air conditioners when they need to meet their peak demand requirements, or meet their requirements.

Interruptible demand is usually a contract arrangement, where the utility can either interrupt or call on the customer to interrupt a certain amount of their demand at the request of the system operator.

The remaining demand response program are captured in our data through the internal demand, which includes adjustments for all the indirect demand side management programs, such as conversation efficiency and so on.

In a preliminary summary of our 2007 summer assessment, we're seeing a small increase in the total impact of direct control load management in interruptible programs, in several of the regional councils, with Florida showing the largest impact, about six percent of the peak. It's grown to six and a half percent for this summer.

The others are more modest, but they do average about two and a half percent. I will note for Jeff's benefit that he must have done some good work in Connecticut, because there's a 200 megawatt increase in demand response in Connecticut, which was a constrained area. So this has helped the resource demand balance.

As the industry, we've seen how our demand response program changes our data collection and assessment of the programs will evolve to better understand and highlight the impact of these programs on bulk power system reliability, and specifically in resource adequacy.

We need to fully understand the impact of these programs on both short-term operating reliability and long-term resource adequacy. In conjunction with our upcoming 2007 long-term assessment, we're going to be initiating a study on the influence of demand response programs on reliability, with the goal being to identify what programs influence reliability, adequacy, the suitable models for analyzing these impacts, and the data collection requirements.

We expect to incorporate the results and enhancements from this study in future reliability assessment work. We're also working closely with DOE's Energy Information Administration on our respective data collection activities, to minimize duplication and improve reporting efficiency.

With regard to on-demand response programs, we're monitoring closely EIA's proposed Form 861, specifically Schedule 6, which proposes to collect more detailed information on demand side management programs. We'll make whatever use we can of that data.

We have a number of reliability standards that refer to demand response. They deal mainly with documentation and reporting. We're working on a resource adequacy assessment standard which will address how both supply side and demand side resources are considered or should be considered in assessing future resource adequacy.

Lastly, at the direction of the Commission in your Order 693, we're evaluating a number of our balanced resources and demand standards, so that we clarify what can and should be counted as contingency reserves and regulating reserves.

To sum up, there's a substantial benefit and potential for demand response to serve as a resource. We're going to continue to actively follow this, and would be glad to report back in the future. Thank you.

COMMISSIONER WELLINGHOFF: Thank you, David. Next, we have the Honorable Diane Munns, former Chair of the Iowa Commission, currently Executive Director of Retail Energy Services at the Edison Electric Institute. Today, she's representing the National Energy Efficiency Action Plan. Welcome, Diane.

MS. MUNNS: Thanks. We commend the Commission and the staff for convening this conference. CEI supports policies that promote customer participation in demand response, and believes demand response is essential in competitive markets to ensure the efficient interaction of supply and demand.

Today, I have been asked to brief the Commission and staff on the progress being made by the National Action Plan for Energy Efficiency on a guidebook on a model energy program efficiency evaluation. After that, I'd like to put the question of demand response in the context of our industry's broader goals for transmission investment, in relation to demand response.

The National Action Plan for Energy Efficiency, as you probably all know, is a collaborative effort of public utility commissions, energy consumers, energy efficiency advocates and consumer groups. The plan is facilitated by the U.S. Department of Energy and the Environmental Protection Agency.

The goal of the plan is to create a sustainable, aggressive national commitment to energy efficiency through gas and electric utilities, utility regulators and partner organizations.

I was the former co-chair of the National Action Plan. Now I am the co-chair along with Diane Grunick, a Commissioner from California of the Advisory Committee overseeing the development of the guide book I made reference to.

The guidebook was identified as a need in Phase 2 of the plan, and from all of the interest right now, I think the group did a very good job of identifying next steps.

It will provide utilities, ISOs, states, cities, private companies and others with a framework to define their own institutional level or program level evaluation requirements. A detailed outline of the report has been submitted for the record, as well as contact information.

This guidebook will provide details on best practice approaches for calculating energy efficiency impacts on a variety of programs. The guidebook is intended to capture the state of the art and after-the-fact documentation of the impacts of energy efficiency programs.

It is policy neutral and will work towards establishing common definitions and terminology. It will also attempt to establish a consensus on basic evaluation approaches, in order to promote consistent evaluations across jurisdictions.

However, it will primarily rely upon and reference existing protocols and documents. It may not answer many of the questions you have asked of the panel, but it will likely provide more detail regarding the limits of existing program evaluation experience for transmission expansion applications.

It is due out this summer. It will define program requirements based on best practices. It will inform key evaluation issues that reflect local requirements and constraints, such as budgets and tolerance for uncertainty, some of the things that Jeff Schlegel talked about.

It will establish consistency in evaluating savings. But clearly, new approaches will be needed. I think that Richard Spring of Kansas City Power and Light is on a panel and will describe the work that the Electric Power Research Institute is doing. We believe that's important work in that regard.

I strongly encourage FERC, ISOs and the states to work closely with EPRI and the utility industry. In my experience, innovative approaches to energy efficiency are most successful when they are developed and supported by the utilities themselves, in collaboration with the regulators.

It is my long experience that you cannot force a utility to do something that it does not want to do.

(Laughter.)

MS. MUNNS: Rather, utilities tend to follow innovations developed by their peers or through collaborative research after careful consideration and proof of concept.

As you know, when it comes to alternatives to transmission expansion and reliability needs, the industry will not compromise its obligation to serve, making measurement and verification one of the essential elements to successful implementation of demand response.

Demand response is clearly a valuable capacity resource, and valuable as an alternative or complement to transmission expansion. But it does involve a different approach, and has been historically taken.

The ability to verify, evaluate and forecast demand resources becomes a critical question. The needs of transmission planners and operators are very different from utility energy efficiency program planners and implementers, or at least they have been in the past.

During the October 12th, 2006 technical conference, FERC heard from several EEI members on this issue. To summarize, the utilities stated if utility operators do not have dispatch control or if there's no effective way to test what's out there, then it's problematic to incorporate it. Utilities must be sure demand response can be operated when it is needed.

In conclusion, I commend the FERC for convening this workshop. You've gathered industry experts to begin to collaborate on answering the difficult questions and developing the tools necessary to expedite the promise of this resource. I certainly appreciate the time that we are spending here today in 2005.

The shareholder-owned segment of the electric utility industry invested $5.8 billion in transmission. This is an 18 percent increase over 2004, and in 2006 to 2009, EEI members plan to invest over $31 billion.

Clearly, demand response can help reduce the risk to the utilities and on the customer side, in implementing these investments. Thank you.

COMMISSIONER WELLINGHOFF: Thank you, Diane. Next, we have President Ray McQuade, President of the North American Energy Standards Board. Ray?

MR. MCQUADE: Thank you, sir. I want to thank the Commission for having me here today to speak about NAESB demand response programs. I'll be the first to admit I'm not the demand response program expert.

But I am a standards expert. I've been doing standards pretty much like I feel all my life. I'd like to talk today about a meeting that we held on April 11th, what began that meeting and initiated it, and then where we're going from there and what role NAESB might be playing in demand response programs.

Just a very brief amount on NAESB, because I think everybody sort of knows us, the same way they know NERC. We're organized in quadrants. This bears noting that the quadrants include wholesale electric. They include retail electric, they include wholesale gas and retail gas.

So we have an organization that addresses the wholesale issues and retail issues and we have a process in place that allows those quadrants to come together to form either joint standards or coordinated standards, and in this case, with demand response.

The requests have been assigned to wholesale electric, but they've also been assigned to retail gas and retail electric. The process that we follow for standards development, is ANSI accredited? It is open.

You do not need to be a member of NAESB to participate in our standards development. You do not need to be a member of NAESB to send comments in, provide input into filings with the Commission or the state commissions, nor do you need to be a member of NAESB to vote.

All of that you can do as a non-member. Of course, we'd love you to join, but if you don't, we'd much prefer having a broad participation. Standards development is initiated either through a request or through an annual plan item, and in demand response, demand side management and energy efficiency, it was initiated through both.

We got a request from North Carolina to do advanced energy, and we also had items in our annual plans for demand response. So clearly, this is getting a fair amount of attention from our membership and from those that participate in those planning processes.

There were some sensitivities, just to say up front, that I want to address, in demand side management. We are not looking to repeat or step on toes of other groups that are already well on their way to developing programs for demand side management.

What we would hope to do is develop standards that enhance and support them, and complement them. As a result, when we put together the program for April 11th, David Kathan from your staff and Larry McSwettie from the Department of Energy were extraordinarily helpful in telling us who to reach out to.

As a result, in our April 11th meeting, we had a wide variety of groups participating in the process, that frankly had never come to a NAESB meeting before. We were very, very pleased with that.

The process that we started came from an annual plan item to review and develop needed model business practices for standardized methods for quantifying benefits, savings, cost avoidance and/or the reduction in energy demand and usage derived from the implementation of demand side management and energy efficiency programs.

The effort would include demand side response, energy efficiency programs in metering, including the curtailment service provider program. As you can see, that fits pretty much the kitchen sink into it.

So with our first meeting, we endeavored to facilitate a session to narrow that scope for an initial phase. Clearly, as a result of the presentations we had and the structured discussion, it was determined to look at the scope for the first phase to the measurement and verification of energy savings, and peak demand reduction from both the wholesale and retail electric market perspective addressing quantities at this phase, not prices.

It doesn't mean down the road that we're giving you the impression prices and valuation is not important. Clearly, it is. There's clearly an interdependency. But we wanted to test the first phase of that.

We thought we could come up with some standards relatively quickly, being able to look at the work products that the National Energy Efficiency Action Plan has done and several other groups have done, including all of the ISOs and RTOs, many of whom were at the meeting and participated and gave presentations.

We're in the process right now of scheduling the next three meetings. In fact, an announcement, I think, is supposed to have gone out from my office today. I think our next meeting is May 24th in Houston, that we have a series of meetings scheduled. Everybody is welcome to come.

We will be looking at that scope statement and further refining it at this next meeting, then moving forward from there. I appreciate the opportunity to talk about this today, and advertise it and maybe get more folks to show up. Thank you.

COMMISSIONER WELLINGHOFF: Thank you very much, Ray. Next, we have Dr. Mimi Goldberg, Senior Vice President of KEMA. Welcome.

DR. GOLDBERG: Thank you for the opportunity to be here. KEMA has been in the energy efficiency and demand response program since 1975. We've been involved with design delivery as well as measurement, verification and evaluation of those programs.

Of particular note in this context, we are currently working with ISO New England on evaluation of the demand response reserves pilot that you've heard about earlier today. We are also working with stakeholders in New England, development of measurement and verification plans for the forward capacity market that's coming up.

Finally of note here, we recently did a study at the California Energy Commission on demand response baseline protocols that was intended as a comprehensive review of what is being done, in an attempt to establish a basis for creating uniform protocols, which of course is always everybody's goal, as long as it doesn't involve them changing what they're doing.

(Laughter.)

DR. GOLDBERG: I'm going to focus on baseline issues in my comments here. I do have some prepared comments that touch on some of the other questions that were proposed.

Baseline estimation, as our first speaker noted, is critical for calculation of both energy efficiency and demand response resources. Meaningful definition and calculation of savings or demand reduction has to start with agreement on "compared to what?"

In principle, the desired baseline is what would have occurred in the absence of the program or the program action demand response event. With that hypothetical, no program condition could be known perfectly for every customer or every resource.

So it would simply be the difference between the observed usage and that baseline.

That calculation would capture all the program effects and all the attribution effects, free riders and power market effects. That of course doesn't happen. In practice, baselines are usually defined by standards or conventions, and attribution effects are then, we hope, separately addressed.

I have some further comments on attribution that I'll defer for the moment. For demand response, if we have a rate-based approach where the customer is paying for what they use and the rates perhaps vary by time of day or critical condition, then the measurement and verification needed for settlement with the end use customers requires only the observed load, not some estimate of what the load would have been without a demand response event.

However, if you want to evaluate the effect of the overall program, there still is a need for estimation of what would have happened in the absence of that structure.

End demand approaches, where the end use customer is being paid some kind of incentive for the demand reduction. We have to say reduction relative to a defined baseline. So that becomes very important.

There's been numerous discussions and proceedings around those issues in each jurisdiction that has this process going on. In that context, measurement and verification for settlement with the end use customer requires the baseline calculation according to some pre-agreed procedure.

Evaluation of overall program effectiveness might still use some alternative calculation methods to deal with baseline.

For the study that KEMA completed in 2003 for the Energy Commission, we conducted interviews with stakeholders on the development and the desired features of baseline methods, as well as technical performance, assessment of a large number of methods. We used load data from utilities across the United States.

One thing we learned from stakeholders that was fairly consistent across everyone was what people want in a baseline. They wanted to be simple, which means it's easy to use, easy to understand, doesn't cost a lot for participants or for operators.

They want it at the same time to be accurate, meaning that it's not biased. It's statistically precise. It appropriately handles weather-sensitive accounts. It's verifiable. It doesn't have any systematic tendency to distort things.

They wanted to minimize gaming opportunities by customers. They want, in many cases, that they can predict in advance that a customer can decide in a day-ahead environment what the baseline will be for tomorrow before they decide whether to bid into the day-ahead market.

Of course, they want consistency with what everybody else is doing. What did we find in terms of technical results? I won't go into exact details of what should and shouldn't be done, but we did learn that some relatively simple methods can work reasonably well for most accounts most of the time.

But no one method will work well for all types of accounts. In particular for accounts that have highly variable loads, there is really no method that's based only on historic load and weather data that's likely to work well.

For accounts that have weather-sensitive loads, methods that do not reflect the event day's weather are likely to be inaccurate. Methods that are based on the average load for prior days without adjusting to the current day will tend to understate baselines and savings, as events tend to occur on particularly hot days.

On the other hand, simple averages with simple adjustments can work nearly as well as the formal weather models for a number of cases. Thank you.

COMMISSIONER WELLINGHOFF: Thank you, Dr. Goldberg. Next we have again Gwen Perez, Internal Audit

Manager for the California ISO.

MS. PEREZ: Thank you. I'm glad today that we're not going through an air conditioning cycling date. I feel a little hot over here, but we're not supposed to feel it.

(Laughter.)

MS. PEREZ: The California ISO's experience in measurement and evaluation of demand response are based on our participating load programs and the trial emergency demand response programs of 2000 and 2001.

I discussed these programs earlier with you this morning. However for both these programs, we used settlement quality meter data as prescribed by our tariff, derived from interval metering.

Interval metering is one of the critical components in the measurement and evaluation of demand response. We also recognize that we do not have the experience in dealing with multiple demand response programs as many of your panelists have, with a variety of characteristics and different measurements.

Therefore, my comments are limited to the California ISO's experience and not necessarily the experience of the state of California's programs.

For participating load programs, the measurement is simple. It's the opposite of how we measure generation performance. For load, we subtract the settlement quality meter data after the dispatch, from the value prior to the dispatch. The difference should be equal to or greater than the dispatch quantity.

This is what the entity will get paid for, and we use our normal settlement process for it. Presently, with the large pump loads, we also have telemetry data available, so operators can verify in real time that the load is coming off as dispatched.

Having this market product, the scheduling coordinator representing the load bids into the ancillary service market. Therefore, we know what is available from the entity.

Our experience has shown us that from the pump load, the ancillary services provided are extremely reliable. Forecasting demand response is much more difficult, and has many variables, such as weather conditions, the day of the week, number of times demand response has been used, timing of notification and customers' perceived need for the demand response.

MR. PEREZ: This summer we'll be working more closely with IOU's, the Investor Owned Utilitys and the CPOC's during the summer months to identify the amount of capability in the various demand response programs on Peak Bay. Our real time experience with interruptible program has shown that some of the programs are more reliable than others. Last summer in our July heat wave customers had a good indication that Monday, July 24 was going to be a stress day. When we called our stage two event for customers to curtail, many of them had already dropped down to their firm level in their tariff.

So one of the things that we didn't see, though, was that the air conditioning programs. Those were very reliable and those megawatts served up when requested.

In the area of demand response for permanence, sustainability and reliability, we're excited about the research happening in the demand response arena. We have worked closely with one of the projects funded by the state where specific circuits in houses are being monitored. The houses are equipped with two-way communication, air conditioning cycling devices. This research is demonstrating that load can be curtailed in these programs in a matter of seconds, supporting the ability of a program like this to participate in spinning ancillary services.

In addition, the researchers are gathering significant data on the technical characteristics of the circuit with many residential customers involved in the program as well as shedding additional light on the processes of marketing and the rolling customers. This summer the researchers continuing with additional circuits and additional homes involved it is important that we measure and verify demand response based on the product that's being delivered aren't defining the characteristics of the product and reaching uniformity of these characteristics.

The measurement verification could be the same across markets. Uniformity in the measurement in this case would promote certainty within companies that have facilities in different markets as well as reduce hurdles for third-party aggregators who want to work multiple markets. Uniformity would support business risk assessments, which must consider consistency, cost reduction and energy needs.

I believe that when one considers developing an industry around demand response, the more standardization the better. Thank you.

COMMISSIONER WELLINGHOFF: Thank you very much, Glen. Next, we have Julie Michals. Julie is the Public Policy Outreach Manager for the Northeast Energy Efficiency Partnerships. Julie?

MS. MICHALS: Good afternoon. Thank you commissioners for this opportunity to speak on measurement and evaluation of demand resources. In particular, on the development and requirements of the ISO New England forward capacity market measurement and verification manual, which I refer to as the M&V manual.

The M&V manual was just recently approved by the NEPOOL Market Emergence Committee and it covered a broad range of demand resources, including energy efficiency, load management and distributed generation, real time demand response and real time emergency generation. The requirements of the manual apply to a range of project sizes from single-site merchant projects to a larger state portfolio of energy efficiency programs.

It represents a first case where an M&V manual has been developed to support resources participating in a wholesale market. Its development will help to create a level playing field with supply side resources. This development will also help to foster interest in an action on developing national measurement and verification guidelines discussed earlier by Ms. Munns and Ms. McQuade. This is important for creating a common currency for energy efficiency, thereby helping policymakers meet energy, economic and environmental policy goals.

In its development of the M&V manual, ISO New

England received extensive input from key stakeholders, including the New England State Program Working Group represented by PUC Commission staff, program administrators and evaluation experts and facilitated by my organization, Northeast Energy Efficiency Partnerships. This group focused its efforts on ensuring that the M&V manual could apply to state ratepayer funded energy programs. But input was also provided by other demand resource parties representing merchant efficiency, load management and demand responses. Efforts were coordinated with the state program working group with these key stakeholders.

From the ISO's perspective, the key objectives were to make the M&V manual work for a range of demand resource types of varying sizes to develop accuracy and precision requirements that would ensure the reliability of these demand resources consistent with accuracy standards for a traditional generator.

For demand resources, stakeholders, in particular, the State Program Working Group, the key objectives were to develop M&V standards that did not necessarily reinvent the wheel, but rather were based on standard practice and existing M&V standards; but included accuracy and precision requirements that were reasonable and attainable without significantly increasing measurement and verification costs and to ensure that the states could bid their portfolio programs into the forward capacity markets in a single project.

From the perspective of the State Program Working Group, the M&V manual provides a reasonable set of requirements giving the key objectives and ensuring that demand resources do result in reliable and verifiable reductions in demand during performance hours. That said, it does remain to be seen whether there will be increased M&V costs that will serve as any impediment to participation, particularly, for the state efficiency programs. This may depend on the level of payments, ultimately, that the states receive from the market.

So what are the key requirements of the M&V manual? I did provide a PowerPoint to support some of my comments here that provide some more detail, but I will cover some of the key areas that are partly addressed by the questions to the panelists.

The M&V manual sets forth requirements that a demand resource provide and must address in their M&V plan, as part of their qualification package to ISO for each forward capacity auction. These requirements, largely build from existing M&V practices, as I said earlier, including things like the international performance measurement verification protocol guidelines otherwise known as the IPMVP, the Federal Energy Management Program Guidelines, existing state efficiency practices and also ISO's load response program manual.

A few areas to highlight for you are that, in developing this manual, while ISO did lay out specific M&V methods and approaches that they identified as acceptable approaches, again building largely on IPMVP and for options provided there, they did provide some flexibility by allowing a provider to propose an alternative M&V method if it could be demonstrated that these were equivalent to the accepted methods described in the manual.

Further, ISO included certain M&V techniques that can be applied to one or more M&V methods, such as combining load shape analyses with engineering estimates. These were important provisions for the State Program Working Group based on current practice.

The other important thing I just want to touch on is that the manual does lay out accuracy and precision requirements, specifically, precision level of plus or minus 80 percent confidence level around the demand reduction value and this also applies where a statistical sampling is used. It further sets out the specific requirements for measurement of equipment classifications consistent with what's required on the generator side for metering equipment and it requires annual certification that the reference documents used for M&V continue are reviewed and approved by a third-party auditor to assure that the are still applicable to the M&V plan.

COMMISSIONER WELLINGHOFF: Thank you very much, Julie.

We have about 40 minutes left before our break. Why don't we take about 10 minutes a piece of questions for the commissioners and I'll defer to my two other commissioners. Phil?

COMMISSIONER MOELLER: Mark, I'll let you start off.

COMMISSIONER SPITZER: Go ahead, John.

COMMISSIONER WELLINGHOFF: Rae, I was very interested in your program you laid out, starting with your April 11th meeting. I'm interested to know a little bit more about that process. You've got three more meetings scheduled. What is the timeline beyond that as far as when you can see that you have a product out.

MS. McQUADE: That's a tough question because standards can be created in as little as four months and certainly as long as one year plus. In this case I don't think it's going to be in four months. We have these three meetings scheduled. The first meeting was to define the scope of the first phase. It was facilitated by Mr. Pickels. He did a magnificent job of directing the discussion to where we could come up with a scope statement for people to put their arms around.

I think the next meeting will end up refining that scope and formulating potential work papers for how to develop the standards. This ought to dovetail nicely with the deadline that Diane mentioned of having her report out by the summer because the next meeting is in late May, followed by a late June meeting, followed by a late July meeting -- basically every month. We hope to build on the work papers and then from the work papers get draft standards and then from the draft standards start looking at those standards to finalize steps for commenting and voting.

My crystal ball says certainly not before the end of the year. This will definitely move well into 2008.

COMMISSIONER WELLINGHOFF: This is a standard that could be used in a wholesale or a retail market?

MS. McQUADE: Yes, but we're looking at the standards activity for both wholesale and retail. So you have the retail component, the individuals that are looking at the state issues involved at the same time as the ISOs and the RTOs and the utilities and the others that are all in the room.

COMMISSIONER WELLINGHOFF: As I understand it, the standard now primarily focuses on peak demand reduction. Is that correct? You haven't addressed yet and the standard won't address, for example, using demand response in ancillary markets.

MS. McQUADE: That's correct. That will be phase two possibly. It could be that when we go into finalize this scope statement that there are some changes made to it so that if people have a desire for us to go in a different direction, they need to show up at the meeting. Yes, what you're doing is important, but you need to look at this aspect at the same time and that certainly could revise the scope.

COMMISSIONER WELLINGHOFF: The next thing I wanted to ask of the three individuals to your left -- Dr. Goldberg, Glen and Ms. Michals. Does anyone of your organizations participate at all in the standards that NAESB's involved in that came out of the California ISO or NEMA. Are you involved in that standard-making process.

MR. NEVIUS: Yes, we've had participants at the meeting.

MR. PEREZ: We have not.

MS. MICHALS: We are participating. We were not at the last meeting unfortunately because we couldn't be there in person, but I understand that future meetings will provide the option of being there either on the phone or in person. We will be monitoring and ensuring that states are aware of these developments.

COMMISSIONER WELLINGHOFF: Rae do you know are there any representatives from an ISOs or RTOs specifically that are participating?

MS. McQUADE: Absolutely, ISO New England gave a detailed presentation. There were a number of questions that helped shape the scope from the New York ISO. We just added a segment in wholesale electric for ISOs and RTOs called the Independent Grid Operators/Planners segment. So they'll end up being involved one way or the other because they'll have to vote on them at the executive committee level. I do expect that we'll see additional -- I think we have four ISOs in attendance at the meeting that participated.

COMMISSIONER WELLINGHOFF: David, I've a question to you with respect to NERC and reliability and its relationship to demand response.

As I understand it, you're about ready to start a study on the influence of demand response on reliability. Is that correct?

MR. NEVIUS: That's right.

COMMISSIONER WELLINGHOFF: Give me a little more of the scope of that study and when you expect it to start and when you may have some conclusions.

MR. NEVIUS: We expect it will give us some guidance for further assessments of reliability, taken into account the role of demand response. We expect to do that by the end of the year. It's being discussed now in the context of our 2007 long-term assessment. As we review the regional self-assessments and do other analysis, we are looking specifically at a lot more deeply this year into the role of demand management. So it's really surveying what's going on, taking into account what is happening in places like New England and elsewhere in the demand response area.

COMMISSIONER WELLINGHOFF: Will that study then also address demand response in its relationship to the reliability standards themselves?

MR. NEVIUS: Not some much to the standards. Only to the extent, Commissioner, that it will talk about how demand response should be taken into account or addressed when you do resource adequacy assessments. We and you cannot set resource adequacy requirements that require generation or transmission to be built and I assume that could be extended to say you couldn't require demand response programs to be built. However, we do have an obligation to assess and report. This standard will get into some detail about how those assessments should take demand response into account.

COMMISSIONER WELLINGHOFF: One final question about that study. Would all look at what would be or try and evaluate the value of demand response vis-a-vis maintaining reliability.

MR. NEVIUS: No more than it would evaluate how generation addition or transmission addition would contribute. We're somewhat agnostic about which option achieves the right balance. It could be combination of generation, transmission or demand response. We'll leave it to others to evaluate which is the best in that particular circumstance.

COMMISSIONER WELLINGHOFF: I think that's all I have. Go ahead, Mark.

COMMISSIONER SPITZER: Thank you, John.

Diane, you stated that you can't force-feed the companies. What strategies could be employed to have them encouraged, particularly in the bilateral markets to adopt both energy efficiency and demand response?

MS. MUNNS: I think my point was that you're so much more successful when you try to align the interests of the different parties to get that done. You've been a state regulator and I think you understand what I'm saying. I think that efforts like this one and the National Action Plan where you shine a light on this subject and get people to start talking about it and identify the barriers. I think the National Action Plan and moving things forward, talking about the barriers, the different rate treatment, starting people to talk about that. These are all really necessary steps.

People need to educate themselves, get used to the concept and start talking about it and that's why I very much commend Commissioner Wellinghoff and how he has used his position here as a bully pulpit and I think marshalling the forces on demand response to get people focused on these things. I think it will take some time, but I have seen a sea change over the last couple of years in people's interest and attitude toward these things and understanding that it's something that we're going to need to figure out together how it is that we make it work. But there are a lot of venues and a lot of approaches from working with the utilities, which I'm doing at Addition Electric.

It's a culture change. It's the culture change from the state commissions and talking about these things and I think that it will be incremental. Success breeds success. As we see successes in different markets across the country, people are going to want to know how did that happen? Is that something we can adapt here.

COMMISSIONER SPITZER: Jeff, you heard my question this morning and it was really apposite to the bilateral markets. There was a subsidiary issue of decoupling. I have very vivid memories of California going through a lot of angst and ultimately there was some objection from some of the ratepayer advocates, but ultimately California proved to be a success on decoupling on the energy efficiency side. That got some progress made. What could you add to what Diane has suggested?

MR. SCHLEGEL: To follow up on Diane's main point, if you want retail customers to take some action, or retail regulators to take some action, and the taking of that action relies on utilities either being advocates in that process or willing participants, willing soldiers to go along I think you basically need to better line up the public interest with the utility private interest or the incentive the utility sees need to be better lined up with the public interest.

If utilities continue to be rewarded for sales and you want them to make fewer sales, you're going to have a mismatch between where you want to steer the system and how the utility shareholders and management are rewarded. While decoupling is one mechanism and one effective mechanism, it's one that's kind of the full step. People, I think, need to move in each of the retail environments to a place where the retail environment and the utility incentives are lined up more with the public interest.

COMMISSIONER SPITZER: The decoupling concept, as I understand it, at least, from a revenue requirement point of view, holds the utility harmless from loss of sales revenues. Are there specific DSM strategies that we could cooperate or urge with the states to provide some incentive maybe beyond just to hold harmless to actually give them a positive incentive.

MR. SCHLEGEL: It's a full spectrum of mechanism to do and I was saying line up the utilities interest with the public interest. One is decoupling, which is the one that you asked about.

On the lower end of the spectrum, it's not quite as extensive but still effective. It's to provide financial incentives for the utility based on the net benefits that it provides to the system. If the utility administers some energy efficiency programs and demand response programs, their incentives would be based on their earnings. A portion of their earnings would be based on how well they do, how well they administer those programs and the degree to which they achieve the goals that we set out for them. That's the performance incentive approach.

Between those two you could perceive, and there are some states that have a combination of partial decoupling. They may not shift say the weather risk associated with decoupling, but they'll shift the conservation fluctuation, combine that with a performance incentive and I think you see people in retail environments trying to find something that will work at least for the transition, even in the fact, at least in some states, of very high and increasing retail rates, which tends to make retail repayers concerned about just how high they're going to increase prices in the near term, so there are mechanism in between performance incentives. And partial decoupling are less effective than full decoupling, but they are steps in the right direction.

COMMISSIONER SPITZER: California has achieved over the last 20 years fairly dramatic reduction in per capita usage compared to nationally. Has there been any evidence on the connection between the degree to which rates have been decoupled historically on the high degree of conservation and low degree of usage?

MR. PEREZ: I'm sorry. I just don't have that kind of information.

COMMISSIONER SPITZER: Thank you, Mr. Chairman.

COMMISSIONER WELLINGHOFF: Phil?

COMMISSIONER MOELLER: Thank you, John. I think I'll start with Ms. Michals.

Your manual is pretty impressive. I haven't looked at it yet, but as far as you know is this the only regional manual that exists.

MS. MICHALS: Yes. I would first clarify. I can't take credit for it being my manual.

COMMISSIONER MOELLER: Sorry, I misspoke.

MS. MICHALS: Yes, I mean, to certainly my knowledge it is the first type of manual that's been developed to support the measurement verification of demand resources in the market. As some of you may know, many states, as Jeff Schlegel did report earlier, many states do have their own technical reference manuals or protocols. California probably being the most comprehensive in energy efficiency evaluation protocols. They do lay out specifics on the types of things that the ISO, FCM manual does. But it's state-specific and it's applied for the purposes of measuring and verifying energy efficiency savings, largely for the procurement that California has where they have efficiency of the first loading order.

So yes, in response to your question, the New England manual is the first of its kind and so I think a lot of people are going to be carefully watching how it is applied and how effective it is and how the different resources can meet the standards set forth in the manual.

COMMISSIONER MOELLER: Do you anticipate for the next iteration being 24 months into it or will there need to be presumably some modifications as you see what works and where measurements are more effective in certain states?

MS. MICHALS: Right. I believe, to the best of my knowledge, ISO does have a process for amending its manuals. I don't know if there's a set schedule for doing so. If it's on an annual basis or if someone can petition to have an amendment made and it can happen on that basis.

I would imagine currently the schedule with the ISO is June 15th, this upcoming June 15th is the date for submitting qualification packages with the M&V plan. ISO will be reviewing those through October. They will go through an iterative process, I believe, talking to the providers to clarify things that they review. Some issues may come up, but I think ultimately it will be close to the commitment period.

There is an opportunity -- I think it's important to note that demand resource providers can update their M&V plans if they gather further data or update studies prior to the commitment period. Because they submit their qualification packages three years in advance of that, they can provide additional information. And so, whether or not there's a need to update that in the process depends on what obstacles or challenges there are.

COMMISSIONER MOELLER: I understand. And although it's not your manual, you were instrumental in bringing the groups together. From what I read, I'm wondering if that's the model that we should take to other regions, assuming manuals are a good idea for that kind of guidance so that someone from the energy efficiency community or who has the right skill set can bring the various interests together?

I think of other regions that similarly have diverse stakes in terms of Iowa and Wisconsin have different thrusts on their demand management. Anyway, your thoughts on that.

MS. MICHALS: Sure. I would say one very important thing that did happen in New England was at the New England Conference of Public Utility Commissioners did pass a resolution last summer in anticipation of the need for their being common protocols for efficiency in New England for the purposes of this FCM and also other policy needs.

My organization had done a study looking at the policies of the different states and how the discrepancies were defined and the different methods used. There was a clear recognition for the need on a regional level for consistency.

In the Northwest, there's a regional technical forum, which covers four states where they do have a set of common protocols. I think California is another place where there's a set of very comprehensive protocols. I think what we see happening, we move on to the national level where we have the EPA efforts, the action plan. We have the North American Energy Standards Board addressing this. How these will all come together I think remains to be seen, but I think the reality is they're all building off of the same building blocks. So we're not going to necessarily see anything brand new.

There is a lot of history and a lot information out there that will be used to support these national guidelines. I would encourage, though, that there be that regional coordination as this process moves forward.

COMMISSIONER MOELLER: Thank you.

I wonder if Rae or David have any comments to that?

MS. McQUADE: I agree with Julie. I think it's important that regional interests are strongly represented in standards development. Indeed, as we end up developing the standards, it could be that the standards not only accommodate, but show the variety of regional differences that need to be reflected so that you're not going to get a one-size-fits-all unless the industry at large all agrees that one-size-fits-all makes sense. I think that's very important. I think the work that Julie and her group has done is critical for the industry.

MR. NEVIUS: In connection with the work we'll be doing, we coordinate very closely with NAESB where our reliability standards, but up against business practice standards. We have a standing arrangement there to make sure that happens. We don't duplicate or leave any gaps.

COMMISSIONER MOELLER: Thank you.

Diane, a quick question. At the beginning of your statement you talked about demand resources being important in competitive markets. Where you limiting their applicability by saying that? Or am I reading more into that than I should?

MS. MUNNS: No, I don't think that they're limited to competitive markets. I think that there's a different way to deliver them, but that we need to find out how we do that in the different parts of the country. I don't know if it's easier or harder. I guess it remains to be seen, but all should pursue them in an aggressive manner.

COMMISSIONER MOELLER: Very good.

John, that's it for me.

COMMISSIONER WELLINGHOFF: Thank you, Phil. I think we still have a few minutes for Commission questions before I turn it over to staff. I have two quick questions for Jeff and I'll let staff go because I know that David probably has some questions as well here.

Jeff, one question I had, looking back on my notes of your presentation. You seemed to indicate that you believe that there's somewhat of a disconnect between the value of demand resources and the value in the market rules and demand resources wasn't extracting, I guess, all the value out there that it could is the impression I got. If you could elaborate on that some.

MR. SCHLEGEL: There's a mismatch. I think I said two points. One is, I guess, a mismatch between where the retail regulators have evaluated and valued demand resource, energy efficiency demand resources and the way they're currently being valued and the market rules for a capacity market is one example. That's not the only example.

The second, your specific question, though, does that practice not count all of the demand resources? It could end up not counting all the demand resources. It depends on the details. What I was trying to bring the Commission's attention to is that rules are rules basically and they set structures and mechanisms for evaluating resources. Those can be limited and therefore can be limiting in terms of the way demand resources are constructed now, operated in other marketplaces.

And to address your question in the way that they're valued, if you're not careful in the way demand resources are valued in wholesale markets and in market rules, you end up in a situation where they're under valued in two ways. One, they could be directly under valued for the specific type of resource they're providing, whether it's capacity or short-term emergency or pricing. But they also can be under valued in at demand resources tend to have more integrated value and when you deintegrate them and you value capacity over here, on-peak energy over here and off-peak energy over there, and C&D capacity over there you no longer have the integrated value of the resource. It's deintegrated in all these various markets.

You need to be, I think, careful as a Commission and also as implementers in the audience that you don't have unintended consequences that the integrative value of demand resources is deintegrated to the point where it doesn't provide the value that it would otherwise.

COMMISSIONER WELLINGHOFF: How do you avoid that?

MR. SCHLEGEL: Most of the questions this morning addressed the interface between retail -- or many of the questions -- retail and wholesale markets. I think the first thing joining on to some of Diane's initiatives and others I think it's important to have consistent policies from the very top, meaning nationally and regionally and then in state. The more you have consistent policies the better able you are to value integrated resources because then maybe FERC doesn't pick up 100 percent of the value of the resource, but you can be assured that the other portion of it is being picked up in a retail environment. So you don't lose the resource because you have a coordinated delivery.

I think the portion of Rae's work, NAESB's work that intrigued me is actually the benefit in monetization of resources because that's an area we had a lot of work in protocols on energy savings and peak demand values, but there's less work on monetization. What happens, for example? What's the economic value of a demand resource when it reduces the market clearing price for all load in the system? There are a few analyses like that in the country.

If you standardize the way that analysis would be done and that analysis would be accepted, that would have a significant impact on the way demand resources are currently valued. Right now most people don't value that impact.

COMMISSIONER WELLINGHOFF: One last question on the M&V aspects specifically. I think you alluded to this, to the fact that you do an M&V, a diversified whole group, many points and participants. In doing such, I got the impression there's some way to, perhaps, lower the cost overall of the M&V on the total package.

In other words, if you had only three points of participation versus a thousand points of participation, you might be able to lower the average costs on those thousand points. If you could expand upon that a little bit on how that might be more integrated into these processes of M&V so we can lower costs and get more participants in, in a general way.

MR. SCHLEGEL: I'll summarize three ways. There maybe more than three. The first one is if you have a thousand points you can sample those points rather than do a census sample. Rather than go out and monitor all one thousand, you can statistically go out and monitor a subset of those and get a reliable estimate.

A second way to do it is by using the measured results from a sample of participants to apply those to other participants for whom they represents. You have participants in a program this year and you have participants in a program next year and those participants are very similar. One is representative of the other, so you can do an evaluation every other year rather than do an evaluation every year. That's become relatively standard practice in evaluation in New England as a way to reduce measurement cost and yet ensure reliability

Then the third way is the diversity of the resource. The resource, it's fundamental nature is that you have lots of changes over thousands of customers. If you think of it just like a stock portfolio, you don't have to worry about one big change or one big outage of a 400-megawatt plant. Instead, there are lots of things changing on and off throughout the period of the resource. The diversity, the investment portfolio diversity actually has a certain amount of reliability inherent in that approach. That allows you to invest less in M&V because actually, if you invest more in M&V, you don't get any more reliability.

You get the same amount of reliability if you pay more for M&V or pay less.

You need to understand the nature of the resources, so you do the appropriate amount of M&V and focus on those places which are the highest contributors or drivers of uncertainty.

COMMISSIONER WELLINGHOFF: One final question I can't resist then. How do you get transmission operators who are used to ramping up a power plant to be comfortable with any one of those three different ways of looking at the other side of the equation?

MR. SCHLEGEL: First, let me say that I very much applaud FERC's Order 890, trying to get people to look broader at other resources for transmission planning and for resource planning. We had the same challenge amongst many of the utilities in many of the regions when people first looked at demand side management or looked at resource planning and it was done through a combination of arm twisting and incentive.

As Diane said, generally, the incentives worked better in terms of the effect. Utilities and transmission owners are nervous because their primary responsibility is reliability. I think you need to do a combination of providing incentives to get there, rules that they need to abide by and gentle persuasion to get there. It's an industry that' dominated by, still, generators and transmission owners, yet, customers are an important part of the component.

FERC is trying to move forward to increase demand response. That's a customer-based resource largely and it's a resource that frankly generation and transmission owners are not that comfortable with, not that knowledgeable about and not that used to. To get there, you need to marry some of the stuff that -- to demand responses if customers matter and marry that with some of the best technology. If you marry the social scientists to the engineers, you'll have a much better outcome than if you just have a system run by engineers.

COMMISSIONER WELLINGHOFF: Thank you, Jeff. David?

MR. KATHAN: I wanted to ask a question. One of the last questions we had in the agenda was, should there be uniformity on how demand resources are measured and verified? That's a question I want to throw to the whole panel. Should there be uniformity or should there be standards or should there be guidelines? Should we use an M&V standard type of manual that New England has developed? Are there enough diverse resources that it's hard to come up with a standard? I throw that out.

Jeff, why don't you start?

MR. SCHLEGEL: I believe there should be increased consistency and there should be a standard approach in the way that M&V has done, but that won't result in uniformed values that people can just pick up and use for demand resources.

The push behind uniformity and to increase consistency is largely one of perception. I would contend many of the places that have the protocols that several of the speakers mentioned that the demand resources in each of those retailer/wholesale environments they're reliable, certainly the ones at ISO New England is doing, certainly, the ones that Connecticut does, Massachusetts, Wisconsin, California -- those are all protocols I'm very familiar with and in each one of those places I would consider the resource to be reliable. However, they don't have the exact same M&V approach. So I think the impetus for standards and consistency is a good one, but it's driven more by perception than it is by lack of reliability.

The resource that is reliable will be perceived as being more reliable if the standards are more consistent across the various constituencies and states.

MR. NEVIUS: I'd have to agree with what Jeff said. I'm coming at it from the standpoint of evaluating resource adequacy. There are different ways to do that. As long as you get comparability of results, I think that's what you're really looking for, not uniformity of approach.

MR. KATHAN: I'll follow up on that. Since the various MOD standards are going to require the various utilities and load-serving entities to supply documentation, what would be the level of demand reduction for various resources? What are the plans on the part of NERC? Will you be developing a common standard or at least a common direction?

MR. NEVIUS: We'll be reevaluating that whole series of MOD standards that refers to DSM or demand response in light of the Commission's orders through our standards process. And as I said earlier, we'll be staying in close touch with NAESB to make sure that what we do is compatible and consistent with what they do from a business practice standpoint. But our approach is to make sure that when we have the data and the people who are operating the system and planning the system have the data that they need to do their job to keep the system reliable.

MS. MUNNS: I agree with that. As far as uniformity and consistency, I don't think you're going to get 50 different jurisdictions remaking the wheel. People just don't have the resources. They want to know it works and I think you will see adaption unless there are legitimate difference that need to be recognized. Then certainly people will bring those forward. But again, I see this as a lot of other processes with education and people understanding what it is that you're trying to achieve. They're looking for something that has been proven to work and then they will, to the extent that it is adaptable to their state or to their region -- they'll do it.

MS. McQUADE: I don't know that I can add anything to that.

MR. GOLDBERG: I'll just make a comment. Common approaches and common terminology make it easier for people to learn from one another, make it easier for us to understand one another and make it easier for the market to develop. That doesn't mean standards, but it means let's talk about things, using the same words to mean the same things most of the time.

MR. PEREZ: Like I said earlier, I think the uniformity in the characteristics of the demand product drives the measurements. So if we can get uniformity in the product, I think that would help.

MS. MICHALS: I would only add part of the challenge and part of the need is the consistency in definition and the greater transparency. If you're able to identify what a particular region or state or what not is using, one is more readily able to aggregate numbers and be able to look at things on apples to apples comparisons. So I would say, consistent with what everyone here is saying, it's not necessarily uniformity we're striving for. It's largely consistency and providing a range of commonly defined methods. Again, getting to the transparency issue is critical.

MR. KATHAN: I have one additional question, unless any of the staff has another question they want to ask. I ask this to Julie. I'm curious. You made a comment stating that the accuracy and precision requirements. I'm curious as to how that is defined as energy efficiency in terms of would that accuracy and precision need to be tighten in providing a capacity product than perhaps what is used for some of the state programs and such?

MS. MICHALS: I'll take a cut at answering that, but may have Jeff add onto that, too. Certainly, for New England states in providing input into ISOs' initial proposal on the precision level in the manual, this was probably the hot issue in terms of what we spent the most time on. I think that would be really a surprise. Largely, because depending on what state you were looking at, there were no real clear standards necessarily on a precision standard. There was more sort of history of generally what had been used and in some states commissions were more clear on what their expectations were. Others less so.

What largely began as a 90 percent confidence with 10 percent precision came from the load response manual that ISO had. That was where we started and then it was largely negotiated based on what was agreed to by the states, with ISO on what was deemed to be an acceptable value and something that could be achievable by the states. I think it is going to require that they do some further research and analysis to meet those requirements. So it's recognized that there is go to be some additional M&V costs. The magnitude is less great.

I don't know, Jeff, if you want to add anything.

MR. SCHLEGEL: Just briefly, the vast majority of the past studies and the current studies going on in New England would meet the 80/10/10 decision of requirements. That's why the states supported it in the State Program Working Group. Those that are not the sample would have to be supplemented or a new study would need to be done.

As Julie mentioned at the end, there were will be some increased M&V costs associated with the state energy efficiency programs applying into the forward capacity market. It's not clear yet how much increase that would be. People are going through that process right now.

COMMISSIONER WELLINGHOFF: We'll take a break then until 3:25 p.m. We'll start back then. Thank you.

(Recess.)

CHAIRMAN KELLIHER: I just wanted to note for the record that Commissioner Wellinghoff very readily surrendered the gavel to me.

(Laughter.)

CHAIRMAN KELLIHER: I knew that he would handle the last panel very efficiently. He's very efficient in his personal deportment as well as his policy goals, a very consistent gentlemen.

Why don't we start with the fourth panel. Let's begin with Steven Whitley, Senior Vice President and Chief Operating Officer of ISO New England. Welcome.

MR. WHITLEY: Thank you for the opportunity to appear before the Commission. These are good times in New England right now. We're getting infrastructure built. We're getting demand response. We're getting more resources coming at us with the forward capacity market. Demand response resources play a key role in meeting overall power system requirements on the New England power system.

Earlier today, you heard from Henry Yoshimura on how demand response has played a significant role in shaving the systemwide peak during critical power supply periods, which enables system operators to maintain needed system operating reserves.

Today I'm going to offer a system plan and an operator's perspective of how demand response can provide solutions to future needs of the New England power system. I will point out how energy efficiency offers advantages for some conditions, while demand response offers advantages for other. The key factor is what the operator can count on.

Let's review the need to plan and operate the bulk transmission system in a reliable manner. We need to plan a combination of resources to meet future power system needs, generation transmission response for energy efficiency so that the operator can keep the lights on a variety of real time system conditions. Planners must address a range of future demand condition and dispatch scenarios. We have to make sure the system is planned according to the NERC standards and the bar has been set higher into today's world of mandatory reliability standards.

A system must be planned to withstand the loss of any single power system element. We also have to plan the system being able to withstand the loss of a second element in the short time after the loss of the first element. We need to understand the electrical characteristics of the problem we're facing as we're planning and the characteristics of the available solutions to understand which resource provides the best electrical solution.

Let's look at two examples. The first one I'm going to call resource adequacy. The first example is a systemwide power supply shortfall that can be projected up to 30 minutes in advance. Clearly, this is a condition where the forecast demand for the next few hours is expected to exceed the valuable supply even after the operator has called on all available generating resources and emergency transactions from neighbors. This is a case where operator control demand response does an outstanding job.

In other words, the system operator can count on demand response to meet this demand. In this case there's time to notify the demand response providers to reduce systemwide demand within 30 minutes. As mentioned earlier, this was clearly demonstrated on our system last August when we reached absolute record demand when our system peak was 1200 megawatts higher than anything we had seen before.

The second example I want to talk about is transmission security. This is when you have a sudden loss of a transmission element that can cause an immediate voltage collapse, thermal overload or instability on the power system. Voltage collapse can actually occur in a fraction of a second. In this case, demand response can't be counted on to mitigate that need in real time.

On the other hand, this is an example where energy efficiency, if deployed much earlier in the right places, could have been a sound alternative to a potential transmission -- the transmission may have deferred the need for that upgrade essentially by offsetting the demand where permitted.

In New England's capacity market, the energy demand response and other demand resources will have the opportunity to compete directly with supply side resources. However the opportunity for demand resources to be treated as capacity is new and the challenges will be new as well. They will have to perform to get paid just like the supply side resources.

In summary, New England's regional planning process identifies system needs and provides an opportunity for a variety of market-based solutions, including demand response and energy efficiency to meet those needs. Our goal is to have a merchant marketplace provide solutions and review the development of a regulated transmission plan as a backstop for reliability.

ISO New England's planning process and wholesale markets are designed to produce the appropriate mix of transmission, supply and demand resources to meet the reliability standards in future years. The amount of demand response in New England has grown substantially over the past seven years and I see demand resources playing an increasing and important role in the future of New England's expansion. Thank you.

CHAIRMAN KELLIHER: Thank you very much.

I'll now recognize William Whitehead, General Manager for Transmission and Interconnection Planning with

PJM Interconnection.

MR. WHITEHEAD: Thank you. I appreciate the opportunity to speak with you today. I'm somewhat in the unique position at PJM to work demand responses. I actually currently have responsibility for doing state government policy, so I work between PJM and the states to help develop policies between the two.

I have previously spent most of my career in the transmission planning and also in Operations. PJM has always considered demand response in its reliability planning process. But rather than spend a lot of time on what we've done in the past, I wanted to spend a little bit of time on recent enhancements we've made to make more a part of the planning process.

In particular, we've put demand response and generation resource and generation by allowing demand response when demand responses to bid in, in the same fashion as generation resources, then be counted in the permitting process through the RPM process. We've also recently expanded our planning process to include market efficiency and economic planning.

The market efficiency and economic planning when it was developed through our stakeholder process was actually developed to include demand response and to provide the opportunity to consider demand response as an alternative or as a complement to some of the transmission enhancements we were considering through the economic planning process.

We've been able to wrap in the demand response into that. Also, as we went through the stakeholder process it was also set up to provide information so that states that were considering retail programs or stakeholders who were interesting in developing demand response programs would be able to be get information from those economic planning processes related to the amount and place of demand response that could be used to offset the need for transmission reinforcement.

We've also started to do some collaborative planning. Many of our states are involved in energy master plans in developing plans for future energy use in the states. We been asked to participate in a number of those energy master plans where we've been able to work with the states on a collaborative basis to look at demand response alternatives, energy efficiency alternative to the typical transmission planning that has been done in PJM traditionally.

We've offered to provide some of our planning tools that we use to analyze transmission reinforcement and to look at transmission reinforcements and also generation resources. We've offered to work with the states to provide this tool to test demand response alternatives as well.

Finally, we've recently completed a strategic evaluation or a strategic plan evaluation. Among other things, we've put together a brochure that talks about a smart grid and the fact that we believe that there is a need for an enhanced technology that would allow the development of demand response and demand resources through advanced communication technologies.

One of the things we've seen, as we've been working with our states and also with our utilities, is that there are a number of initiatives out there -- smart meter initiatives and different types of initiatives. All those initiatives are not as well-coordinated as we would like to see them. We believe these coordination efforts and the efforts to improve communication and the efforts to put communication protocols in place that would allow all of these different technologies to communicate with each other and communicate with a central area will become very important as we go forward and try to implement and make sure that demand response gets a similar footing as other types of resources.

I'd like to thank you for the opportunity again and I look forward to taking any questions when we get finished.

CHAIRMAN KELLIHER: Thank you, Mr. Whitehead.

And now I'd like to recognize Sandra Levine, Senior Attorney with the Conservation Law Foundation. Welcome.

MS. LEVINE: Thank you. I appreciate the opportunity to be here and thank the Commission for its commitment and leadership in recognizing the important role that demand resources can play in the wholesale market.

The Conservation Law Foundation has been involved in energy issues for over 20 years. As many others have shown during these panels, there have been tremendous opportunities for demand resources in today's wholesale market. The same is true for transmission planning. Coming as it does at the end of today, I think transmission planning probably represents one of the more nationed opportunities for demand resources, but one for which there is a huge potential.

In most areas, demand resources is a means to actually address reliability and congestion problems on the grid that are largely untapped. The challenge, as with other areas, is to create a level playing field so that demand resources can be used effectively to meet society's power needs in the most cost-effective, reliable and environmentally-sound manner.

The advantages of doing so are significant. Energy efficiency remains one of the cleanest and lowest cost resources. If we're not using it wisely and using it well in our grid, we're probably spending too much. We're certainly polluting too much. We're losing some economic opportunities and we're selling the grid short in terms of reliability.

As far as the current situation, most transmission planning first gages what demand is or is likely to be in the future and then builds poles, wires and other transmission infrastructure to meet that demand under varying circumstances. Demand resources or energy efficiency, to the extent that they're considered at all, are generally factored in only as input to the demand forecast. What's completely absent from that is seeing how those same efficiency measures could be used to reduce demand in congested areas and thereby either avoid or delay transmission expansion or other grid enhancements.

I've identified in the written materials I've provided an outline of an effective transmission planning process as well as some key elements to the great demand resources into transmission planning. I won't go over all those. I'll focus on three particular obstacles and some solutions that I think are very feasible.

The first is the financial disincentives for efficiency. Jeff Schlegel talked about these to some extent as well as Commission Spitzer. Utilities make money by selling more electricity and they have a financial disincentive to reduce demand. Ratemaking mechanisms such a decoupling or mechanisms that would separate utility profits from the volume of electricity that's sold is certainly one means to overcome this and should be used.

A second obstacle is the lack of expertise and effective standards for transmission planning. Demand resources are mostly seen as a square peg that's being asked to fit into a round hole. Transmission operators certainly know how to plan and evaluate poles and wires very well. They often feel as comfortable with demand resources. When looking for reliability solutions, they wants something that looks, feels, and acts like a transmission project.

If that's a standard that's going to be used, we necessarily are going to be excluding some very valuable solutions. Instead, we need to define the standards based on their ability to meet these needs that we have. For example and by analogy, we all say we need shoes. We need something to cover our feet. We need them to be comfortable to walk in, at least most of the time, and keep the weather out. But we mean to say that everybody needs to have brown shoes with brown laces on them. That would probably exclude a lot of the shoes in the room.

So if you define the standards based on what the need is instead of something very specific that you're familiar with, I think there's a great opportunity for more resources to come to the table and meet those needs.

The third issue is funding parity. The same opportunities need to exist for funding for demand resources as currently exist for poles, wires and other transmission solutions. In some areas like New England, there is a regional cost sharing for transmission facilities. But that same regional cost sharing is not available for demand resources that can meet the same reliability needs as transmission projects.

If there's always unequal funding opportunities, demand resources will always be having to meet tougher requirements than transmission and will always be at disadvantage, expected to meet needs at a lower cost and with greater impacts.

CHAIRMAN KELLIHER: Thank you.

I'd like to recognize Dr. Eric Woychik, Executive Consultant of Strategy Integration.

MR. WOYCHIK: Thank Chairman Kelliher and Commissioners and staff for the opportunity to be before you today. I represent Converge, Inc. Converge has 6000 megawatts of demand response in place and holds about 350 megawatts of long-term dispatchable 40 outsource demand response contracts.

Let me address the five questions you presented for this panel. First, could transmission planning processes generally be not considered demand response as an alternative or a complement to transmission upgrades.

Transmission planning by utilities and ISOs have improved. Demand response is obvious applications that is not addressed based on the business case to fix specific locational restraints and to reduce the need for policy must-run generation. This is just starting to be done in some places in the U.S., such as in California. This exemplifies that in the main current transmission planning processes are not sufficient.

Second, the research planning process should consider all options. Demand response, energy efficiency, generation, including distributed generation, and transmission and fully address locational resource adequacy. Planning and cost effectiveness should thus include the following: monetize the avoided cost of generation transmission redispatch and contribution when demand response is added; monetize the market price reduction and market power mitigation benefits of demand response; count dispatchable demand response for resource adequacy as is done in a couple of places we've heard today; and monetize reduced emissions and the use of environmental dispatch with demand resource.

In the planning process, the most straightforward metric is to use cost, but KW/year to represent the capacity of each alternative, which enables apples to apples comparison. This recognizes the option value of demand response.

Regarding the third question, major advantages with demand response are that it can be installed and made operational very quickly, much faster than comparable transmission capacity. It provides incremental benefits immediately and has no sighting or negative environmental impacts. Certainly, demand response avoids "not in my backyard" or NIMBY concerns.

Demand response allows direct transmission deferral, which Converge provides for Rocky Mountain Power on the Wasatch front a transmission constraint at ISO New England in western Connecticut. In addition, dispatchable demand response can be use flexibly to address congestion as each customer enrolled in a program can be separately addressed and activated. Pardon me for using the program term. Moreover, demand response provide more megawatts at times when transmission delivery capacity is less during peak demand. Thus, when demand response is used with transmission, it can reduce the risk of outages or congestion such as when unanticipated loads or generation shortfalls materialize, which planning cannot anticipate.

Demand response is unique in providing multiple benefit streams. That is, it displaces generation plus transmission plus distribution plus provides environmental mitigation and hedging for reliability for fuel risk as it uses no fuel and for market price spikes.

Fourth, wholesale market design and ratemaking can encourage demand response, especially through the use of real-time pricing and time-of-use pricing. Real-time pricing can use wholesale ISO prices that are passed through to customers such as in the ComEd, Commonwealth Edison Program, to distinguish from most TOU programs. We emphasize that for time-of-use pricing to effective, it must use large price differentials that are meaningful like those in the Gulf Power time-of-use program.

Converge is very involved in both the Converge and the Gulf Power initiatives. We also suggest that time-of-time use and integrated time-based demand charges should be applied to transmission based on marginal cost principles to enhance the economics of transmission use and of demand response.

Fifth, it seems appropriate to use an incentive rate of return to encourage long-term demand response contracts and to allow demand response equipment and installation to be rate based as is done for transmission. Long-term demand response contracts provide for certainty of load relief. Fully outsourced demand response contracts shift all the risks of customer acquisition, operations implementation and equipment warranty away from customers.

Fully outsourced demand response contracts, thus, should be encouraged through the use of incentive ratemaking, not unlike the Commission's current incentive rate of return now used to encourage participation in RTOs and ISOs. Thank you. I look forward to the discussion.

CHAIRMAN KELLIHER: Thank you very much.

I'd like to now recognize Richard Spring, Vice President for Transmission Services with Kansas Power and Light.

MR. SPRING: Good afternoon. Thank you for the opportunity to address this committee.

What I would like to do is change the roles a little bit and discuss with you demand response as I see it today and where I think it maybe going in the region. I would first like to discuss the work that the Electric Power Research Institute is doing around energy efficiency and demand response. How the Southwest Power Pool is approaching demand response. We are a member of the Southwest Power Pool at a regional level and one or two of the successes of demand response, KCPL.

To start of with, I'd like to let you know I'm not a policymaker and I'm not a economist. I'm a transmission system operator. That's what I do for a living. So at this point, I'd like to reiterate my view that given the role of transmission planning, if done properly, in delivering the energy to customers, demand response has the opportunity to provide the load-shaving ability necessary to preserve grid reliability at times of peak demand as well as deferred lead for new transmission and generation.

Having said that, going on to the Electric Power Research Institute, in January of this year EPRI launched the Dynamic Energy Management Initiative to blaze a path towards effective demand response. The initiative is addressing the needs of utilities and other stakeholders to deploy technologies which facility smart power delivery, operation, load management and end use systems.

As part of the initiative, representatives from more than 40 electric utilities will work with EPRI to address electricity savings, demand reduction and peak load management. The new program will focus on the analytics and information on the economic and environmental impact of Dynamic Energy Management and the infrastructure component system, testing and development. To help accomplish these goals, the Electric Power Research Institute is doing a study in their labs to examine, one, high efficiency end use devices which you heard about earlier today; IT addressable electrical devices so that we can have a easy communication link; control systems to optimize performance with demand; two-way communications to allow automated control devices to respond to price or demand reduction signals and dynamic systems that allow real-time integration of consumers energy management systems into the system and market operations.

They're using these tests to help utilities with their demand response efforts by developing guidelines for capturing and documenting system requirements, mapping technologies to requirements and developing system management security policies which reflect the need for interoperability and the ability to manage and secure equipment over large scales and for integration within the ISOs and RTOs.

At the regional level I mentioned Kansas City Power and Light as a member of the Southwest Power Regional Pool Transmission Organization and the SPP is taking an active approach to demand response. While they have been mulling a demand response strategy since being recognized as a regional transmission organization in 2004, the discussions have become much more substantial and in January of this year the Southwest Power Pool Regional State Committee held a workshop on energy efficiency, demand response and resource adequacy.

It's the expressed desire of the Regional State Committee to have a strong regional strategy for implementing demand response on a regional basis rather than the local approach that is used today. Currently, the state's regulating the Southwest Power Pool treat members demand response participants differently, resulting in wide variations between states. When SPP transitions to a regional strategy, hopefully, making the treatment more uniform -- and we expect it to bolster the role of demand response across the region -- a report on how the demand response will integrated into the energy imbalance market operating today in the Southwest Power Pool is due to this Commission in August of this year.

Integrating demand response into the transmission planning process and markets on a regional basis also mitigates another challenges -- reliability of demand response in the face of peak demand. While testing the peak capacity of the power plant is simple, determining the capacity that can be freed up at peak times through demand response is more complicated and sophisticated. I think we heard a lot of that from the previous panel. The rules around that will need to be engaged in, through a meaning degree for transmission operators to operate the grid reliably.

It seems now I just getting to run out of time and I'd like to put in a little advertisement. Kansas City Power and Light has 5 percent of its peak demand under a demand response program.

With that, again, I would like to thank you for the opportunity to address this Commission and staff. And the Electric Power Research Institute, Southwest Power Pool and KPCL are committed to demand response and will continue to look at this opportunity with a reasonable focus to maximize load reduction and grid reliability potentials with the right tools and enablers, demand response can move from a complement to transmission service upgrades to an alterative.

Thank you for your time.

CHAIRMAN KELLIHER: Thank you, Mr. Spring and the other panelists.

Why don't we go with 15 minutes each for Q&A? Why don't we start with Commissioner Wellinghoff.

COMMISSIONER WELLINGHOFF: Thank you, Mr. Chairman.

Let me start first with Steve and Bill, the two ISO/RTOs here. I believe both of you indicated that you do have demand response integrated into your transmission planning process. Is that correct?

MR. WHITLEY: That's correct. Any market alternative can participate in the transmission planning process as responding to the needs we've identified on the power system.

COMMISSIONER WELLINGHOFF: My question is, if you'd expand on that a little bit, explain to me how that's done. If, in fact, demand response is part of that planning process could, in fact -- could it either defer or completely substitute for a transmission alternative.

MR. WHITLEY: The best way to do that is maybe to give some examples. One of the first big problem areas we had in New England was Southwest Connecticut. It's sort of a black hole for power consumption. We were serving megawatts at 115KV. And to give you a comparison, in another place where I used to work, TVA, we served Memphis, which is about the same size, with five 500KV lines and a power plant in the center of town.

The operators watch it like a hawk, so serving 3500 megawatts at 15KV is not a real good thing to do. So we immediately ran studies, saw that we couldn't meet criteria. When you load a system up like that, we looked at all kinds of alternatives, including demand response and higher voltage transmission. Higher voltage transmission turned out to be the best solution. It actually reduced losses by 20 megawatts by bringing in higher voltage into the area. That's every hour.

We did use demand response, though, to help buy time because we couldn't get that transmission in there overnight. We did an RFP and put out a request for megawatts for specific locations in that area to help protect reliability to defer the need for that transmission because we just couldn't do it and that really is what jump started the demand response program in New England.

As I mentioned earlier, it's not the perfect solution for every problem because if you have a contingency that causes voltage collapse in a matter of cycles, you just can't get to it fast enough. You have to have it on all the time to keep the load down. That's where efficiency works the best. We were able to use it, to count on it when we got down to the margin on the system. We have 30 minutes time to activate those resources to reduce the demand. There are some pluses and minuses. Some of the minuses were half of that was dirty diesels that we were cranking up to get on it, so the air regulators weren't real happy with that. But it jump started the whole industry and got things going.

I think, over time, we're going to see a lot of replacement of those older, dirty resources with newer technology with the monies available in the forward capacity markets, but there's an example where you have to look at the characteristics of the problem you're solving and see what does it take to solve it. Is it just transmission? Is it just generation? Is it just demand response? Or is it sort of a combination of all of the above? In Connecticut, it's a combination of all of the above.

COMMISSIONER WELLINGHOFF: Before we go to Bill, I want to cycle into one comment you made with respect to the response time down to less than a second. You can't really rely on the demand response. Did you hear Mr. Pratt talk about his experiment on the Olympic Peninsula? What he was doing there?

MR. WHITLEY: I did hear that. I'm very interested in that. If that can be developed to work, I'm going to jump all over it.

COMMISSIONER WELLINGHOFF: You can get a bigger experience going in New England.

(Laughter.)

COMMISSIONER WELLINGHOFF: There are a couple of thousand homes in New England or something.

I'm sorry, Bill. Go ahead.

MR. WHITEHEAD: We do a demand response in the priming process now. That's primarily -- up to this point, it's primarily been what we call the one-time active load management. They were essentially interruptible resource. We did look at those. When we did planning, we looked at those as the equivalent to generation resources. With RPM now, with demand response able to bid in, in a similar fashion to generation resources, then we will look at demand response resources through RPM the same as we'll look at generation resources. That will be done on a comparable basis as long as they're on an equivalent basis and long as we have a fair amount of certainty that the demand responses will go ahead.

Theoretically, they could replace the transmission project. They've also been very useful in emergency operations. The operators often use the demand response, particularly, where they have voltage problems. At times of peak load, they'd use the demand response as an emergency response to help manage the voltages and manage loading on the transmission system during emergency procedures as well. So it's been useful in both the planning process as well as in the operations.

COMMISSIONER WELLINGHOFF: Following up on Sandra's comment, the question goes back to both of you because it does appear that what you're saying is the demand response could, in fact, substitute in certain instances for transmission. Do we feel that in doing so, in your current tariffs and processes, you would provide funding parity to do that because funding parity is the big issue for me? If we do transmission over here, we do demand response over here as a substitute. They should have some funding parity to make sure they're funded in a comparable way.

MR. WHITEHEAD: Again, with our tariff, our generation project replaces the need for a transmission project. They can essentially get some "but for" costs for having either reduced or eliminated the need for a transmission project. The same kind of rules would apply to demand resources because, again, they're being treated comparably to generation. There is the possibility that they eliminate a plan for transmission projects. If they could get some "but for" costs for transmission, that wouldn't be necessary if they go ahead. They're treated literally in the tariff exactly like generation resources.

COMMISSIONER WELLINGHOFF: Would they be treated like a transmission resource, though, in essence? Could they get capacity, in essence, if the demand resource created capacity, for example?

MR. WHITEHEAD: They could get capacity similar to a generation resource. They could get capacity payments. They could get a form of capacity payments as well.

COMMISSIONER WELLINGHOFF: For increasing capacity?

MR. WHITEHEAD: In our tariff, generation and demand are treated as market-based alternatives to transmission. PJM we can order a transmission project to be built, but we can't order either demand response or generation. So generation and demand response are market alternatives to a transmission project that might be order through the transmission-planning process.

COMMISSIONER WELLINGHOFF: Steve, did you have a comment? Go ahead.

MR. WHITLEY: Transmission is infrastructure. Just like Bill said, generation and demand response are on the supply side. They're in the market competing with each other to pay for the infrastructure. We have a tariff that doesn't pay capacity. It pays cost, a cost to build with a rate of return and we don't pay the generators that unless there's a real market problem. We don't pay demand response that unless there's a real market problem. They go out and compete with each other based on the revenues that are available in the market.

I think we've really gone a long way to create a level playing field now that we have demand resources and energy efficiency competing in the capacity market now. You saw the responses that we got. I think that's real encouraging, but transmission is a different thing. That's the infrastructure that we need to keep the lights on, move power north, south, east and west.

To meet NERC criteria, I don't really see some way of comparing apples and oranges when you start talking about paying for generation and demand response that way.

COMMISSIONER WELLINGHOFF: That's what I'm trying to think through. Isn't demand response, in essence, functionally substituting for both transmission and generation.

MR. WHITLEY: I see it more as functioning for the generation, not necessarily for transmission. It's not doing all the things transmission is doing to move power, to handle contingencies and all the different things that it can do in real time with the instantaneous capability that transmission gives you.

COMMISSIONER WELLINGHOFF: What it's doing is it's relieving congestion because it's located at the load where the transmission has to bring the generation to the load. You're eliminating the need for that transmission, bringing it to that load -- in fact, you've opened up that load congestion pocket with a demand response. So it really is doing both.

MR. WHITLEY: Just like generation would be doing the same thing. So I really see it as apples to apples with generation and not apples to apples with transmission.

COMMISSIONER WELLINGHOFF: But the generation needs the transmission to get it there.

MR. WHITLEY: Unless the generation is located in a load pocket as well.

COMMISSIONER WELLINGHOFF: Bill?

MR. WHITEHEAD: I guess I would agree with that. The generation obviously could locate far from the load and need the transmission system to get to the load. Or the generation could locate at the load and it would be very similar to what a demand response program would do. It would eliminate the need to move the generation across the transmission system.

COMMISSIONER WELLINGHOFF: Eric, Sandra, do you have any comments on where we've gone in our discussion here?

MS. LEVINE: I think demand resources are not treated on a par with transmission. And also, very often identified that, yes, demand resource and particular energy efficiency can avoid or delay the need for future transmission projects and should get the benefit that a transmission project would get for providing that same service. It has some functional equivalence to generation and some functional equivalence to transmission and should be allowed the benefits of both, which I think there's one thing that has been avoided in the discussion.

When you site a transmission line, you're always wrong. You are wrong because you thought the generation was going to be in a particular location. It's not. You're approximately correct. You thought the load in the future was going to be in particular situations. They're not. You're approximately correct. If you had demand response with it, particularly, if you want to downsize the transmission somewhat and increase the scope of the demand response, then you can deal with the contingencies that occur.

One of those major contingencies is congestion because the generation load is never where you want. That's the complement aspect. I think the substitute aspect is that you can reduce the transmission peak capacity very significantly. You can do that to defer the transmission. The security issue is always going to be there. You can use demand response to just lop off the top 100 hours of the demand. If you lop off those top 100 hours, the security issue is always there. The issue you can deal with in terms of security is to use very fast demand response.

Oxy Chemical in Texas is one example. It's as good as automatic generation control. It's within cycles, just to address that. There's not a lot of that demand response out there. I hope there is going to be more of it. There were discussions today about experiments in other places. That would be very important. I think it certainly is a substitute and a complement.

COMMISSIONER WELLINGHOFF: Eric, do you have any comment on the funding parity issue?

MR. WOYCHIK: I think that funding parity is certainly not that. I agree with Ms. Levine. The problem is that there's a traditional desire to increase rate base, frankly. There's such a strong incentive by the financial entity of any utility. Moreover, it's not a chicken and egg problem. Demand response is not known in a lot of places and not used, so transmission is always used first.

Moreover, the transmission is going to be rate based and you're going to get all your expenses and you're going to get a rate of return. You don't get a rate base and rate of return and expenses that are comparable with demand response.

There's also uncertainty and less of a track record about revenue recovery at the on-demand response.

COMMISSIONER WELLINGHOFF: Thank you, Mr. Chairman.

CHAIRMAN KELLIHER: Commissioner Spitzer.

COMMISSIONER SPITZER: Thank you, Mr. Chairman.

Let me make an observation and maybe get some comments before I ask questions. I think we need demand response. I think we also need transmission. I think we need both. There's not a false choice here.

In the West, it is very difficult to sight generation within load pockets because of air quality and most of the cities in the Rocky Mountain states have the inversion, so we had great difficulty sighting even state-of-the-art gas plans.

In the load pocket in Phoenix, there is -- I would agree with Commissioner Wellinghoff to the extent that demand response in the West does serve as a value with respect to transmission as well as generation. I'd also say it's hard to sight transmission lines, much harder than power plants. The opponents -- the lines, by and large, do get sighted, but that doesn't mean it's easy. There are a lot of costs, not just economic costs, absorbed by the transmission owners. There's a lot of bloodshed as we try to sight these and very often the opponents who object on aesthetic largely make the arguments that the line is not needed, either reliability reasons or for economic reasons and where the state regulators or the federal regulators in concert with the states adopt programs that support energy efficiency and renewal resources and demand response. That gives those sighting authorities the ability to look the intervenors in the eye and say we have done everything that we can to do reduce peak load through efficiency, through locally-sighted renewable resources and through demand response. Having done that, now you have to do your part. We're going to have sight this line. You have then the moral authority to do what needs to be done. So I think both. There is not an opposition or a dichotomy or an either/or.

Let me ask Sandra, you gave a very good description of the process in New England. Commissioner Kelly and I were just recently at the board meeting. There was a presentation on demand response and the stakeholder process. It's interesting. What I heard at the board meeting is very consistent with what the stakeholders say. That's a good thing.

(Laughter.)

COMMISSIONER SPITZER: What specifically has been successful in New England and what aspects of those successes can be employed in other places?

MS. LEVINE: I'm not sure I can cite a lot of successes in terms of transmission planning in New England. What I was noting was the lack of a resource parity. In England, I know there is sharing of costs for transmission in New England. I think that same system is not in place throughout the rest of the country. There is some other areas that have similar cost sharing.

Success, I think, that we have seen is including demand resources into the capacity market. I think that will go part of the way towards dealing with some of the problems of transmission and reliability, but probably won't get you all the way there.

COMMISSIONER SPITZER: Mr. Spring, you talked about some successes with the Southwest Power Pool. I want to explore two aspects of that. One, we've gone through this with the states. States have different regulatory models, different constituencies and they should. They should be responsive to their constituencies.

States are not similar situated. They're going to have different economic as well different policy choices. What lead to the success you alluded to? How was that achieve getting the states to come to form of consensus.

MR. SPRING: You have to look at the regional differences and the market differences. PJM, ISO New England all have very congested areas, very dense loads. The Southwest Power Pool the loads aren't as dense. There's not that much difference between the different jurisdictional entities. If you look at all of this primarily coal-based generators, we're transmission owners. We're all vertically integrated. We all have obligations to serve, so there's not that much difference between the individual entities or members of the Southwest Power Pool.

On a state basis, of course, there are different regulations and different requirements in each one of the facilities. But I will attest that I think the regional state committee is forward-looking in finding ways to get around the differences that they have in their regulatory requirements to get us the regional solutions we need.

I give you the example of getting an RTO. For many years it was not meant to be that Southwest Power Pool would get recognized as an RTO. Through the efforts of or regional state committee and our regional regulators, that came to fruition once we came to the idea that size doesn't matter but market rules do.

The load is so diverse in the Southwest Power Pool. We have 11 major load pockets. The rest of it is rural cooperatives. I think that makes a difference. When you look at the requirements of a balancing authority in the Kansas City metropolitan area, other people look at it around Oklahoma City, Tulsa and those kind of things. We get to be smaller models of what you're seeing in other markets and I think that helps in the conclusions that a regional solution is probably the best solution we can have on any number of items.

COMMISSIONER SPITZER: Your states are, relatively speaking, low-cost jurisdictions, vertically integrated. There's a lot of discussion about Southwest Connecticut. They've got an extreme situation, both with transmission constraints and high rates. That's an easy sell. How were you able to make the sale where you've got the vertically integrated entity and you've got, relatively speaking, moderate rates?

MR. SPRING: I think this is an answer to your question. Where do we get demand response fitting into the equation of planning in the Southwest Power Pool. It's primary from an environmental standpoint. We are looking at our demand grow by 3 to 5 percent a year, which is going to necessitate building some major baseload, most likely coal units.

At least in the case of Kansas City Power and Light, we've come to an agreement with the Sierra Club that, yes, we do need to add that generating capacity. But at the same time we are going to cover any new load by energy efficiency or demand response solutions. Right now we've committed to by 2008 having 375 megawatts worth of energy efficiency and demand response in place in our footprint and continuing that on because we are primarily coal in our part of the Midwest and need to add additional coal and the environmentalists not wanting to see that happen, but we come to these agreements and these other programs become much more valuable into the portfolio and the generation mix we have.

COMMISSIONER SPITZER: So these were consent agreements?

MR. SPRING: Yes.

COMMISSIONER SPITZER: And they had the added affect of deferring further investments as well as arguably not fill --

MR. SPRING: Yes, by 2015 it will postpone the additions of what would be nominally five 77-megawatts simple cycle combustion turbines to get the peak if left unchecked.

COMMISSIONER WELLINGHOFF: Dr. Woychik, what do we do to make more progress in the non-RTO regions?

MR. WOYCHIK: That's a great question. You expect me to answer that in five minutes?

COMMISSIONER SPITZER: Absolutely. You've got 554.

(Laughter.)

MR. WOYCHIK: If I could answer it in that, I would take it. I thin k the use of demand response in the context of this discussion demand response, I think, can be very effectively implemented if you use effective real-time pricing. I think you can use the equivalent of market based rates. You could use the equivalent of a WattSpot, ComEd program.

Instead of using .2 PJM, you're going to put forward a prescriptive, very serious time-of-use differential with that. That's the real time pricing component. People will have notice in that like they have in the Gulf Power Program. You will provide as well, ideally through a thermostat and/or a control system, automatic pricing called a rate guard component. You would have a dispatchable demand response component as well and you would have an environmental dispatch component.

For example, my northeast -- I'm from California. Don't hold it against me. My Northwest colleagues I don't think they ever want to go there. They don't want an RTO.

So thinking of them, it is well people in the middle of the country we'll doing very well without RTOs. Still, I think, we need to have effective demand response. I think there are ways to do that -- the Southern Company, for example.

I grew up, if you will, watching that and in Southern Company they have an extraordinary price exchange information program which helps to coordinate and make for a very effective equivalent demand response there. So it wasn't the answer you wanted I think.

COMMISSIONER SPITZER: Well, I'll divine from that a lot can be done in, in individual rate cases. Mr. Spring talked about there litigation. I don't know if it was part of a rate filing, an application or a lawsuit. I think you've got a lot more flexibility to be innovative in a regulatory context as opposed to a litigation context where the state commission can impose parameters and have oversight where a state court can't. But absent a general rate proceeding, what do you think the FERC can do to advance the ball in those jurisdictions where we're not going to have an RTO.

MR. WOYCHIK: I think the clearest opportunity, even in regulatory jurisdictions such as California or any other place, is to properly define the avoided cost for capacity. This is something that hasn't been done very well in a lot of places. Then you have something to compare transmission lines with -- demand response programs.

In the context of California, we have a very well-defined system for TDG environmental market effects for energy efficiency. That's all KWH defined. You need the equivalent for capacity. In other words, per KW amount dollars per KW year it needs to be differentiated. I have been critical of the lack of that across the nation and I think New England -- if the New England plan to do that gets down to hourly levels, and I'm told it does for capacity prices, that is the equivalent of what I think we need across the board at the national level for jurisdictional and states as well as ideally "munis" would adopt that. With that, you have the building blocks for economically justifying and comparing all alternatives.

COMMISSIONER SPITZER: You look like you were ready to say something? You pass? Okay.

Mr. Chairman, thank you.

CHAIRMAN KELLIHER: Thank you. Commissioner Moeller.

COMMISSIONER MOELLER: Thank you, Mr. Chairman. Just thoughts on today.

I appreciate the fact that you put this together and that Commissioner Wellinghoff has shown so much leadership in this general area. I've been looking forward to today. This panel was the one that made me a little nervous because similar to what Commissioner Spitzer says I'm a firm believer that demand response is a crucial part of us moving forward in the next three to five years -- probably the most important time ever. But I am also a strong believer that we're in a major catchup mode in this country on transmission, so I want to make sure that at least, from my perspective, the signals are sent that both are important.

I think back on my experience with the issue. I painfully cut my political teeth in the late '80s in the state of Washington. We passed through the legislature probably at the time the most progressive residential energy code in the nation, yet we had two major heat zones in the state and we had major -- and still do -- electric heating load based on historically being the last place in the country to get natural gas and historically the cheap electricity prices. So it was very complicated and yet it wouldn't have happened without the leadership of Bonneville at the time, which provided a lot of the money and went to the homebuilders to get the codes done. That's obviously at the residential level.

Similarly, where there were transmission constraints -- I think of Puget Sound, the City of Seattle, essentially demand response was kicked in as an alternative to transmission then and now because it made sense and the other parts of the state where either demand wasn't the same or transmission was easier to build, it wasn't as much of a focus.

I guess I'll lead off with questions to both New England and PJM. Steve, thank you once again for your hospitality when you hosted me in February. Just kind of your thoughts on that prospect of demand response in a sense already being captured by means of it being difficult to build transmission in particularly congested areas.

MR. WHITLEY: Certainly, transmission is difficult to build anywhere in New England, but it has been done. We have five states that have sighted three 45KV lines. The ones going to Boston are in service. The first one into Southwest Connecticut is in service. The 345-line in Vermont is now in service and the new interconnection with New Brunswick between Maine and New Brunswick will be in service by December.

Every one of those proceedings the question about demand response came up. Could demand response be a viable alternative to this particular project? In every one of those cases the engineers had to show what the characteristics of the problem were. Would demand response really solve these contingencies or would it possibly delay the need for the project a year or so. How could it work out?

In all of those case the overwhelming need for the line showed that the line needed to be built to improve the transfer capability across the system to the load pocket or with the other interconnecting neighbor, but demand response had a role as well. Again, like a lot of folks have said. You need them both. They play different roles, but they are different animals.

When you have a bulk transmission network and you have a drought that affects resources on one end of your system, that bulk transmission system helps you bring resources from across the system and from your interconnections to serve that load. When you have nuclear shutdowns or when you have ice storms that effect imports and so forth, we see all of those things happen. That's why a transmission system really plays a critical role, robust, viable bulk transmission system. Demand response also has a critical role for those few hours of the year when you really are in a bind they can shave that peak in a beautiful way. We've seen it done. I think it has a growing potential in the future based on a lot of the things we've heard today, but I think you have to look at the characteristics of the problem to see what the best combination of things that you need are to solve the problem.

COMMISSIONER MOELLER: Bill?

MR. WHITEHEAD: Probably the toughest job for a transmission planner is to realize that you have three options essentially. You have to try to balance the three options.

As Steve said, in some cases you may need combinations of all three to make it work. How you decide which of the three and how much of the three is not an easy decision. Again, I think the fact that we have been able to put an economic planning or market efficiency process in place allows us to do a lot more analysis around scenarios --- the wintertime scenarios and the things like what is transmission? We need it by 2012. If it doesn't get built by 2012, what other things can we do more quickly? We're including cost of emissions and market efficiency analysis so we can get an idea that generation was going to be sighted in a certain place, what would the emissions cost add to the cost of the generation? I think the toughest part is to balance it all out.

We do have an advantage in that we will be able to do this analysis. We do have an analysis, I think, based on the fact that we can work with our states to help them understand the types and amounts of demand response that might be useful. There are going to be different situations depending on whether it's a peak problem, potentially an off-peak problem, those kinds of things. Is it strictly a peak problem? Is it energy over a long period of time kind of a problem? Those types of things, again, I think we have some tools we can apply to the problem and I think we just need to find ways to work with our states on the retail side to help make those programs viable and then find the right combination of programs to make the transmission system and the wholesale markets work more effectively.

COMMISSIONER MOELLER: Thank you.

Sandra, I don't mean to put you on the defensive here, but I probably will. I presume the Conservation Law Foundation supports more renewable development. And again, many times those resources are location constrained and there's just no way to get them to the market without more transmission and the demand side just isn't going to get those developed. I guess I'd like your reaction to that.

MS. LEVINE: I hope you don't think it's schizophrenic to say that Conservation Law Foundation as at the same time working with the ISO to build and bring transmission to the wind projects that are going forward in May and at the same time we're opposing expanding transmission projects to serve load areas where energy efficiency or demand response would be a better means to met that meed.

Overall, the transmission system is to help get power where it needs to go. Efficiency, as you've recognized, would not entirely replace that transmission system, but it can certainly work to allow the transmission system to work more effectively and more efficiently. And where load pockets exist and transmission expansions are being driven by increases in that load, that could be offset by energy efficiency. That is probably a better way to address that need.

COMMISSIONER MOELLER: Eric, in the materials there is a reference to -- you dealt with, I guess, a situation in Utah where a transmission was avoided. Can you elaborate a little more on that?

MR. WOYCHIK: Yes. In Utah, it's called the Wasatch Front. It's very close to Salt Lake City. There's major transmission constraint. There was residential growth that occurred so quickly that it was difficult to build out the transmission. Moreover, there was a distribution constraint. We offered 90 megawatts of direct load control for residential. They don't need to build out the transmission and the resulting distribution constraint. So basically, I'm not correct about this, but my earlier numbers that I had are about 10 to 20 megawatts of that could be dedicated for addressing the distribution constraint and 50 to 70 megawatts could always be dedicated for the transmission issue and the whole 90 megawatts could be used at any time.

Moreover, it's ramping capacity is as fast as anything combustion, turbine. We show that we can get that up, the entire megawatts, in 45 seconds. Moreover, we give Rocky Mountain Power knowledge the day before of what megawatts they can expect where locationally when they push the button and they can push the button locationally. So they're a pleased customer. We're pleased to have worked with them.

COMMISSIONER MOELLER: Thank you.

Richard, you mentioned the consent decree that you signed or agreed to, a pretty ambitious 345 megawatts.

MR. SPRING: 375 megawatts.

COMMISSIONER MOELLER: That goes to the point I was trying to make, but probably didn't. We all had a hand in this, but everybody has a role. You can't decree demand side management. It might be a state regulator allowing adequate rates of returns on those investments in the Northwest. It could be the rule of the federal power marketing agency, Bonneville.

In either setting, the rates are giving a direct financial impact to allow it to happen. It's multi-layered and complex. Can you elaborate a little bit more on how you're going to make sure you get that done?

MR. SPRING: We're regulated by two states, Kansas and Missouri. In one state we are able to capitalize our investment in these programs and get a rate of return on them. That still doesn't make up for the lost revenues you would see by not having those megawatts sold.

In the other state, we've got a proceeding going on. We've got test programs going on so that we can quantify what the best rates treatment for that set of customers is. We hope to have that finished by this summer. I think we're getting to be a lot more energy conscious. We're getting to be a lot more environmentally conscious as a section of the United States and I think it's spilling over and I think it's going to come out.

Cost recovery of any investment is something you go and you argue about in rate cases. One party thinks you're making too much. One party doesn't think they're making enough. But I think with a cooperative environment we have with the two commissions right now this being at the forefront of both the governors' agendas, I think that will proceed very smoothly and very quickly.

COMMISSIONER MOELLER: Thanks again to this panel and the efforts you made to be here. I appreciate the efforts, particularly of the Chairman and Commissioner Wellinghoff for bringing this entire set of issues to a little brighter spotlight.

CHAIRMAN KELLIHER: Thank you, Phil.

I just want to ask a couple of questions and then turn it over to staff to close out this panel discussion, unless my colleagues have more questions. But I admit I'm still struggling to understand how demand response can be an alternative to transmission. To me, that suggests it's a substitute for transmission. I just have a hard time understanding that.

If you look at an analogy, you look at highways. I don't view a highway as a substitute for local trucking. It allows a longer haul truck to compete with a local truck, for example. In electricity, it seems the purpose of this exercise is to have supply and demand in balance at some reasonable price going forward. I can see how demand response competes with and substitutes for generation, but I still don't see how it really substitutes for transmission. And you look at the Southwest Connecticut example -- let me ask Ms. Levine. Do you think that demand response could have obviated the need for the generation, the transmission upgrades in Southwest Connecticut? Did you all oppose those upgrades?

MS. LEVINE: We did not oppose the upgrades in Southwest Connecticut. I actually do not know enough about the specifics and the metrics of Southwest Connecticut to say whether it could completely do so.

I guess one thing I wonder is, when you're thinking about demand response, are you thinking that to include as much as energy efficiency?

CHAIRMAN KELLIHER: Yes, I can see how demand response can compete with peaking or base-load generation. I can see that.

MS. LEVINE: Okay. If you consider it as broad as including energy efficiency resources, if you have a load, and I'll say like Southwest Connecticut, but I'm using it in general terms. But a significant amount of load that is there, there is difficulty reliably bringing the electricity there to keep the lights on. What measures could be taken? Think over perhaps a 5- or 10-year time horizon. I suggest this probably should have been thought about 5 or 10 years before the crisis hit. Are there efficiency measures that could be put in place at every single one of those office building that would reduce air conditioning load, which I know is driving the demand in New England -- actually, something that Converage works on.

If those measures had been put in place, how much demand would be reduced and would it be sufficient to obviate the need for that upgrade. It's not going to replace the transmission complete, but it might avoid the need for the upgrade that's being considered or delay the upgrade.

CHAIRMAN KELLIHER: I guess that's perhaps part of the issue then. Southwest Connecticut didn't have 5 or

10 years really. They didn't have the time to really explore the most robust energy efficiency approach perhaps, but if the experience in Southwest Connecticut was that you did rely on energy efficiency, but that was really to buy you time to complete the upgrades.

MR. WHITLEY: That's correct. The state had a very active energy efficiency program that I think put out like $80 million a year. We encouraged them to focus those dollars in the southwest, not in the northern part of the state, but the southern part of the state and begin doing that. There were other complications. The southern part of the state, the generation there is very old, very dirty, very inefficient. We have to run it day after day after day, even in the milder weather to keep the lights on. So the transmission was critical. It was a critical issue -- got to get the transmission resourced in there so that you can have flexibility to do almost anything else. And at the same time we couldn't do that overnight. So we jump started the demand response initiative there with a lot of money beyond what the state was paying to buy us some time.

CHAIRMAN KELLIHER: Did the demand response allow you to retire some of that older generation earlier?

MR. WHITLEY: No. We're still counting on that, but once we get the transmission -- we have the first phase in there now. It's already caused a big reduction in congestion. We already see that. It's allowed us to start doing maintenance on the other ones. We couldn't even do maintenance on them because they were loaded up so much.

But what it will do it's going to allow those older units that inefficient that are at the right places, right close to the load centers where the transmission is already there and it's going to allow them to repower over time with cleaner technology, more efficient technology as time moves forward. But without the transmission, you couldn't do that.

CHAIRMAN KELLIHER: Yes, sir?

MR. WOYCHIK: I think what was explained in that example is -- I will just generalize to a very simple example. If you need peak power, you would otherwise, if you could, you'd put a combustion turbine right in the middle of that load center. You'd put it right beside the old generation and you'd turn the old generation off, retire it or leave it there for when you really need it for something extraordinary. So you wouldn't use transmission arguably. You'd put generation in the load center.

There is one option. It's load at the center. In lieu of that, you're going to put transmission to take generation to the load center that you have to serve. It's usually a problem of criteria violation and usually it's voltage. The voltage is sagging because the load is increasing at peak or at some points. If you don't build the transmission, you don't put the combustion turbine there.

Let's say that load is air conditioning load. Why not just turn down the air conditioners? That's what the demand response program does. In the most direct situation, you're trying to serve super peak. You don't want to put a generator there and you can't build the transmission. It takes too long. So you need to do something in the meantime, go straight to the end use. You then reduce the peak. You reduce the i2r to the end use. You then reduce the peak. You reduce the i2r to losses at the super peak.

You've created a higher load factor for the system. It's running more efficiently. You've got more revenue at the same or lower costs and rates are lower. So the whole idea that you've always got build a transmission line or that demand or energy efficiency can substitute in certain situations I think really --

CHAIRMAN KELLIHER: The effects are different, though. The effect of a successful demand response program in an area could be to reduce transmission congestion. It could be to reduce prices, but it would seem to me the effects would tend to be me local than some increase in the expansion or the upgrade in the Southwest Connecticut transmission grid. It would have effects outside of southwest Connecticut. It seems that the energy efficiency improvements in southwest Connecticut probably had effects in southwest Connecticut, but I'm not sure anywhere beyond that. But the transmission upgrades might have had more of a regional benefit.

MR. WOYCHIK: They can be apples and oranges, but --

CHAIRMAN KELLIHER: I'm struggling to try to understand that.

MR. WOYCHIK: If you take 100,000 customers and reduce their air conditioning load, that's 100 megawatts. Then the older generation you have sitting there is maybe turned down for part of the time and it can serve other things and your transmission system is less loaded, so you can do maintenance and at load peak times you can shift power across the system. So you're going to increase efficiency, reducing loading on transmission, make existing generation more available. If you're trying to get more power from Quebec, you know, don't do demand response.

CHAIRMAN KELLIHER: Great. Why don't we turn to staff. You can close this out in the next 15 minutes or so?

MS. CAIN: I have first two questions. The first one is just a clarification. Dr. Woychik, you mentioned that demand response helps voltage situations. Do you mean it reduces the power transfers and avoiding voltage support or with air conditioners it reduced the load.

MR. WHITEHEAD: For PJM, it basically helped reduced the load across the transmission system, which then relieved the voltage problem. It was reduction in load that allowed less of a flow across the transmission in a fairly localized area.

MR. WHITLEY: The same. I would say you have to do that before the contingency happens. You can't wait for a contingency to happen and then say, oops, I need 300 megawatts. You're going to be down the tubes too fast. You have to reduce the load first.

MS. CAIN: My second question is we keep talking about having demand response, the generation and the transmission on a level playing field. In transmission planning, we do contingency studies of transmission lines and generators. Do we do anything similar for demand response? What happens with the demand response programs?

MR. WOYCHIK: I think one thing that hasn't been done is an evaluation of demand response and what its forced outage rate is. If you want to make an equivalence and assume that you could do a CT or a transmission or a demand response for a location, what's the forced outage rate of the demand response? For us, when we do residential, such as in Utah, if we're going after 90,000 customers, if only

80,000 show up or 85, we only have 80 or 85 megawatts. It's a different forced outage rate. We never have a full contingency, if you will. In other words, only 95 percent of the time does that demand response show up. It shows up 100 percent of the time, but maybe not all of it.

In other words, you may not get 90 megawatts all the time, but you're always going to get 80. The forced outage equivalence is something I think needs to be done.

MR. WHITEHEAD: Again, for PJM, we do obviously keep track of forced outage rates for generators. We also look at demand response programs that we had historically and we have what we call an IOR factor. It's similar to a forced outage rate. The demand response program is at 100 megawatts. I think our factor right now is like .95. We would count it as 95 instead of 100 the same as if a generator had a forced outage of .95 we would count it as 95 megawatts instead of 100. We do similar things for both of the demand response that we have and the generation that we have.

MR. WHITLEY: I think our experience has been really good in New England with the reliability performance of demand response programs. I also think that demand response providers actually over-subscribed. In other words, they're promising you're 100 megawatts. They're probably signing up 120 because of the penalties associated with the program. I think that's a great way to do it because there's the variation of what might be going on in all these individual places.

As far as looking at the loss of demand response as a contingency -- in other words, we're counting on 300 megawatts in this zone and maybe it won't be there. Since it's so dispersed, it doesn't lump up as big as the large generating units. So I think we've got it covered because it is dispersed the way it's managed.

MR. KELLY: When you're planning generation and transmission, you're planning assets that are going to be in place 30 or 40 years. How is it for demand response? Is that something that is promised to be there for the long term or not and how do you take that into account?

MR. WHITLEY: In ISO New England, our planners are very involved in review of the demand forecast and what all makes up the demand forecast, what's there, what's not there, what are the states doing? Now it's the forward capacity market we have, which has more of a longer term obligation and there are significant price penalties if any of these resources don't show up. It's not a slap on the hand anymore. It's the loss of a lot of money if they don't show up. So that's giving us a lot more confidence that these programs are going to be there through the study period.

They're making money. They're making a lot of sense. I think we have a lot more confidence than maybe we would have five years ago.

MR. WHITEHEAD: I'll just give you form PJM's standpoint again. Demand response, typically, has been on a year-to-year basis. You had to commit by some point in order to be available for the summer peak, but it was on a year-to-year basis. With the new capacity market with RPM, demand response is not making a three-year commitment. So there's a little bit longer term commitment in terms of demand response being around for some period of time.

MR. WOYCHIK: We are very strong in supporting and asking for support on long-term demand response contracts, so the Utah Power Program, the San Diego Gas and Electric, New England and others, we would like to be able -- excuse me. PG&E's contract is five years. We're ideally getting contracts, putting together contracts that are 5 to 12 years in duration and if they can be longer duration, that's all the better. In those cases, we are on pay-for-performance. If we don't produce the megawatts, we don't get paid. In fact, we pay the penalties.

MR. KATHAN: I have a couple of questions. The first one going a little bit down into how the ISOs and the utilities model demand response. In our report we did last summer we asked the number of the regional entities, ISOs, the majority of them said that they would take demand response. They would forecast how much it is and take it off their peak demand and they would plan the system accordingly based on that. There were a few of them that actually did incorporate it directly where demand resources were actually looked at as a resource.

I was curious from Steve, Bill and Richard how is the demand resource modeled in each of your circumstances?

MR. WHITLEY: In ISO New England, I think our modeling is probably both ways. In other words, we take a look at, as we do the forecast, what is energy efficiency initiatives are in the planning of the states and so forth now that we're going to have this forward capacity market model coming forward.

We're also going to now get information on what's actually cleared in the market that we're going to get. They're going to have financial penalties if they don't show up. We have some resources, demand response resources, actually a big chunk of them that are only available for us when we're in Step 12 of our emergency procedures, which is right before firm load because the dirty diesels can't count on them unless you go all the way through all of your steps before you get to that, before you use it.

They're not as flexible as energy efficiency would be. That would be knocking the load down all hours.

We have to look at all of that in combination.

MR. WHITEHEAD: We look at it based on the type of demand response. Certain demand response is strictly peak serving. So obviously, we'll take that off-peak. Certain energy efficiency and other types of programs may flatten the load a little bit or may actually reduce the load, so we'll model those and put them in the load forecast rather than it's just strictly peak shaving. We look at the type of demand response and then model it accordingly.

MR. SPRING: Currently, we do the four snapshots a year where we take moments in time and then run a contingency analysis on that point in time. Demand response in each one of those slices of time is shaved off the peak. We use it to modify the peak. We have been trying to figure out how to scenario analysis in there to where you get a better reflection of the variability due to season of some of your demand response resources so we can do our planning based on that rather than your one cut in time where you do your n-1 contingencies, your n-2 contingencies with demand response just reducing your load.

MR. KATHAN: One last question asked to Sandra about the building of that line in Vermont. I believe the legislature passed a law. Could you speak a little bit about that experience and what's the process that's happening right now?

MS. LEVINE: There was in Vermont a proposal for a transmission expansion in the western part of the state. That was one that Conservation Law Foundation did oppose citing the increased reliance on energy efficiency and other demand resources that avoid the need for that expansion. The expansion was approved by the Public Service Board, the equivalent of the Commission in Vermont. They noted in their order that there wasn't sufficient time to put in place energy efficiency measures that might have avoided the need for that project and provided that a new docket be opened to examine what changes needed to be made in the transmission-planning process going forward so they wouldn't come to that same crossroads again when they felt they had no choice but to approve a transmission project because it was coming in at the last minute.

At the same time, the legislature passed a law providing for a broader transmission planning process that would better include energy efficiency and other demand resources and also include local generation industry to get generation as well. That's currently being considered by the Public Service Board in Vermont, an improved planning process, the outline of the testimony I provided here is it based on testimony that the Conservation Law Foundation provided in the State of Vermont as well.

CHAIRMAN KELLIHER: Colleagues, any other comments?

COMMISSIONER WELLINGHOFF: Just a quick comment. I wanted to comment on some of these issues on transmission. I want to make clear that I believe that efficient and cost-effective transmission projects should be sighted and built and I think this Commission should approve them. But I think we also need to recognize that there is competition for capital out there and to the extent that there are cost-effective alternatives such as demand response and energy efficiency, I think we need to look at them very carefully.

I think there are instances where conservation energy can substitute for transmission. The problem is one of timing and the problem is also one of capital cost allocation and I don't know how we mesh those things together, but that is what I'm trying to explore, how we mesh those things together in a way that hopefully we can look at all things equally to determine what is the most cost effective thing to do to the extent the transmission, again, is cost effective and efficient, can provide reliability and economic benefit to consumers we should be doing that.

But to the extent that there are alternatives that are lower cost that can do the same things, we should do those first. It all comes back to -- you know, what I did back in Nevada in 1983 in the Nevada planning rule, what we call the least cost utility plan. That's basically what we're getting back into in sort of a regional way with what we've done with Order 890. So it's going to be a one step at a time process, but one that hopefully we can all explore together. Thank you.

CHAIRMAN KELLIHER: Thank you.

I just want to thank the panelists and the panelists on the prior panels for all their help today. It's been a very productive day with us. I want to thank Jon for his leadership and for organizing this conference today. I thank the staff for the excellent preparation of the Commission and to my colleagues for spending the day here as well. I think it shows we recognize there are challenging facing wholesale power markets and inadequate demand response is one of those challenges. We have to look at what are the options available to the Commission to improve demand response in the organized markets.

I think that's really the question at hand and what exactly we do I don't know. But I think that's a questions we really have been studying today and I just want to thank you for your help today. With that, we're adjourned.

(Whereupon, at 4:55 p.m., the above-entitled matter was concluded.)