

**Harvard Electricity Policy Group
Forty-first Plenary Session**

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RAPPORTEUR'S SUMMARY*

Session One. Mandatory Reliability Rules and Market Design

The need for additional attention to reliability is not necessarily at odds with increasing competition and the improved economic efficiency it brings to bulk power markets. Reliability and economic efficiency can be compatible, but this outcome requires more than reliance on the laws of physics and the principles of economics. It requires sustained, focused efforts by regulators, policy makers, and industry leaders to strengthen and maintain the institutions and rules needed to protect both of these important goals. Regulators must ensure that competition does not erode incentives to comply with reliability requirements, and that reliability requirements do not serve as a smokescreen for noncompetitive practices.

Blackout Task Force Report, April 2004, p. 140.

As we move forward with the Electric Reliability Organization (ERO), this prescription for consistency between market design and reliability rules requires filling in the details. When and how might rules developed for one purpose undermine the other? What would be the impact of markets on the form if not the purpose of the reliability rules? How can the issues be joined? What pitfalls should be avoided?

Moderator.

Great taste, less filling, great taste, less filling. Our topic is similar; is it reliability or is it the market? How can both exist in the same product in a fluid way?

However, after the blackout there has been an enormous deal of cooperation. I'm not saying the blackout was a good thing, but it improved cooperation and understanding. The engineering community is in many ways changing their thinking while retaining the basic principles that they've always held.

Speaker One.

I represent the perspective of the engineering profession. The engineering and economics communities sometimes say different things. At a recent DOE panel there was an enormous animosity between FERC, a government group, and NERC, the reliability organization.

I'm going to divide my talk into four parts. I'll first talk about the IEEE USA principles. These are principles for restructuring put together by engineers. Unanimity was a requirement for each of the seven principles. Second, I'm going to present some major concerns for system operators from a system reliability perspective. Third, I'll discuss whether NERC standards are

* HEPG sessions are off the record. The Rapporteur's Summary captures the ideas of the session without identifying the speakers.

needed. I'll finish with my own comments and perspective.

Some of the seven principles of IEEE will sound like motherhood and apple pie. While they are obvious, it's very difficult to engineers to agree on even these issues. First is that there should be some minimum reliability criteria. Nobody should be able to be outside of that. Reliability is a common interest and there should be some minimums that apply to everybody.

The second item is compatibility in the pricing strategy. Prices should provide proper incentives for reliable behavior. There are instances where people are being paid to do things that contribute to unreliability. We really need to align, economic signals can't be fostering unreliable behavior.

Third, incentives for effective planning, construction, operation and maintenance of the infrastructure should be incorporated into the market. If there is a market failure, the engineers often deal with the resulting problem. Their mentality is focused on running the system with the right tools.

Long term resource adequacy as reflected by install reserve margins are necessary to assure sufficient supply. This is strongly related to the previous item. A key issue that has been occupying FERC is reactive power. This reminds us that technical aspects which are important to reliability are not the first words that come to everybody's mind when they're talking about energy. Technical issues can become important.

Five, compatibility must exist between the regulatory and institutional frameworks, and the technical frameworks. This is very important. The rules of physics in many of the proposed systems often do that. But we haven't addressed every important technical issue in this area.

Six, policy makers should establish a clear and stable framework. Uncertainty of rules is a huge problem for policy and a big deterrent to progress, to making things work, markets work, etc.

Finally, the design of state administered retail rules. There's a big disconnect, and I'll show a slide perhaps if I have time a little later, between what we want to happen on a general national way and the fact that the retail side is separated. FERC does not have jurisdiction over the retail side in most instances, let alone entire transmission networks. So these outline the official positions of IEEE and there's a white paper that's available as well.

Now I'll address four issues of concern derived from conversations with engineers familiar with NERC and its procedures. First, there's a problem with ramping; huge blocks of power going on and off peak causing ACE [area control error]. The system is supposed to operate at 60 hertz plus or minus a little bit. If it doesn't, it's like a broken altimeter and all of a sudden you have the plane going up and down. Same problem with the frequency. One solution is that maybe this notion of on and off peak is old-fashioned. We should disband it, it's a legacy notion.

Second, when large disturbances occur, the markets cannot adjust fast enough to cover the outage in an economic manner.

Third, TLRs [transmission load relief] are the ultimate weapon of the operator in many areas. This is a system that tells you outside of market means how to get the system back in balance and relieve constraints. This is solely a curtailment mechanism, not a pricing mechanism. I have previously criticized TLRs because they don't work in an economic context and they can be gamed. However, engineers argue that we really need them. There are cases where they are the only thing that's going to work.

Fourth and finally, large penalties should be levied for deferring maintenance and improper training. Operators should have EE degrees. Right now operators are simply people that are trained. If this needle goes here you do this, if this needle goes here you do this. They are well

trained but if unusual situations arise they don't know what to do. Better training is required.

My own comments on these items are as follows. First, we can improve regulation markets to address the problem of ramping. New York is doing a good job in this regard. A better regulated market removes this problem.

Second, reserve markets, particularly locational reserves, are not reserves. They are critical, and can help address the problem of disturbances. The only kind of reserves that make sense to me are locational reserves.

Third, TLR in many systems is not used as a backup emergency process but as the primary means of handling congestion management. That is totally wrong. Further, TLR is too inflexible. In an emergency you have to do anything to save the system, outside the market if necessary. TLR is another set of rigid rules that we may have to bypass anyway.

Finally, with penalties some rules are necessary. However, telling generators when they should do the maintenance, and how, may be going too far. The market and its incentives to generators are sufficient to do this.

Part three of my talk concerns NERC standards. These are 380 pages long, a pretty big decision. It addresses a number of topics and this is part of the problem. When most people think reliability, they think narrowly. However, NERC attends to many practical little things that make up the issue of reliability. Even the categories that the standards cover are daunting. Resource and demand balancing, interchange scheduling, each standard begins with the purpose of the standard, then it tells you what they're going to do, etc. It's much larger than most people think.

NERC will presumably, but not necessarily, evolve into the reliability organization under the supervision of FERC. It's better to think of NERC as an FAA, the Federal Aviation Administration, primarily concerned with safety. However, as we know in electricity it's almost impossible to separate the commercial marketing

function from the operation function. Prices are determined by current conditions which are affected by the system operation. They are inseparable. It's like having the FAA run the airplanes and the radars but also run the market. You cannot separate operations entirely from the market. Under some conditions, you've got to have the ability to make every plane in the air land immediately regardless of the market impact. That authority exists, and needs to exist, to do anything at some level. However, these emergency actions should be the exception, not the rule. Normally, things should function pretty much automatically with little market interference. It's simply a matter of rules.

Let's discuss two NERC standards as examples. Resource and demand balancing standards help to maintain the interconnection frequency within defined limits. That's their objective and they are appropriate. Now, how it's done. To a large extent it can be done entirely with markets.

Disturbance control standards [DCS] exist to ensure balancing authority; the ability to continuously use reserves to balance resources. In case of an outage, standards on how you use your resources to bring the system back in balance are needed. Obviously, the system must be kept in balance at all times. The rules that say how that is to be accomplished. To some extent, prices and market signals will do it but if they don't that's what that standard is about.

Some standards are essential. All standards are there to facilitate system operability and ensure reliability. Unless there is a proven market substitute for a standard, the standard should remain. We shouldn't throw them away until we have a proven market solution. Then, we can eliminate the standard or modify it so it's compatible with the market mechanism.

The FERC legislation may vacate all standards on day zero as soon as the organization comes on. That would be dangerous. Let's make sure the market solutions are there. It's sometimes more complicated than just balancing energy. Clearly, many standards will have to evolve.

Likewise, I think the market structure must also evolve to better accommodate reliability.

Locational reserves are a significant problem. The correct solution is far off. People are beginning to address it and this will reduce incompatibility between the market wants and the reliability rules. If markets evolve in a manner that recognizes reliability, fewer mandatory rules will be required.

Finally, simplicity and transparency are essential. Whenever there's a problem, we add a rule. This occurs even in successful markets. Whenever PJM has a problem, people want a rule to deal with it. Instead, we need a better design, with fewer rules. As simple as possible, (but no simpler).

Price caps are insidious and can result in major distortions. Consider the gasoline situation and politicians chastising people for excess profits. This kind of response dampens market activity under conditions of scarcity.

Operating a system reliably is in the interest of everyone and some market rules impair reliability. For instance, at one point California had price caps in the day ahead and the real time. That was a major contributing factor to the crisis in California in 2000. These rules don't create incentives for a reliable operation.

Speaker 2.

First I'll discuss the NERC market interface principles (which are on their web site). Surprisingly, the NERC principles have less economic content than the seven IEEE USA principles. This is indicative of the challenge we have in front of us.

I did read through the complete standards from NERC and decided to summarize by using word searches of the 343 pages. I searched for the word *economic* and there were few hits. They all said the same thing, "for emergency, not economic reasons." I searched for *cost* and found only one; "purchases made regardless of

cost." I searched for *price*, and also *tariff rate*, no hits. This lack of market acknowledgement in 343 pages of standards suggests we have a long way to go in constructing mutual reinforcement between market designs and reliability standards. However, it can be done and needs to be done. The question is where to begin.

Let's start with market and set the focus on bid-based security-constrained economic dispatch. Next we need to address market designs for security constraint. This is simply a reflection of reliability concerns and issues. The usual market design approach hasn't gone as far as it should. It simply defines reliability standards and limits as fixed constraints on the scope of the economic dispatch.

Early discussion of this market design question focused not on we're *doing* it wrong, but rather we're *pricing* it wrong. If we have reliability standards, then we need prices that are consistent with operating conditions. Early solutions included LMP [locational marginal pricing] and associated operation constraints on transmission contingency limits, thermal, voltage, which are interface limits typically in our representation and stability constraints. This simply describes our current situation.

There's a separate issue of planning limits and constraints on installed generation capacity, transmission capacity and deliverability. These don't involve short term real-time design and must address other issues like resource adequacy. The fundamental starting point is how to get the economics to be consistent with fixed limits. Recently, some people have begun to understand that there are some tradeoffs involved in this, and we can have some price responsiveness and flexibility.

I'm going to focus on a few NERC standards that are critical for market design. The first illustrates concerns for inflexible requirements. This first example from PJM concerns operating reserve requirements. The requirement is specified via first contingency/largest contingency effect with slightly different rules in different locations. In essence, this is how much

you need and it's what we have to have. There's good logic behind that but it's not handled well within the markets.

ERCOT has an extremely inflexible requirement. It is always 2,300 megawatts. Whether it's the middle of the night or 4pm on the hottest day, that's the requirement. As a result, the Texas market monitor reports show that prices in their reserve market are all over the map. Prices were often over \$10 per MW even if reserve capability was more than 2,000 MW higher than the requirement. At these times, marginal costs for supply should be zero, and prices should be cheaper. There's a problem in the market design here. We're not reflecting opportunities and getting the prices right.

Second, in the energy demand component of real time markets a large part of the demand is not price responsive. If you run models that account for opportunity cost, and derive the average value of lost load, there are definitely times when prices should be very high.

A similar question is implied for the separate issue of operating reserve demand. Assume the operator is close to having involuntary curtailments, say first contingency rules, and they're worried about blackout. They might respond by refusing to let operating reserves go below a threshold. They have to curtail some load to preserve operating reserve flexibility. In this case, you should place operating reserves at the value of lost load because it's the same tradeoff. When you're above that we should be willing to pay less but not zero for that level of operating reserve.

This is a standard problem for a fixed level of demand. There should be some price responsiveness. The pricing rules should reflect the operating conditions and reinforce everything, most importantly, reliability. If the market is constrained on capacity we might only get low prices if we only assess the energy market, but if it includes a scarcity of operating reserves you should get high prices. There are lots of market examples where we don't do this. A slightly different scenario could be if a bad storm is possible in New York so the operator

goes to third and fourth contingency transmission constraints for operations. However, we don't introduce those constraints in the pricing rules, and prices go down when demand has increased. There's something wrong with that because it's not reflecting what's really going on.

Planning standards also involve a lot of arcane regulation. Generally the NERC planning standards say one day in ten years. What do they actually mean by that? The realities of those standards are much more complex. One excerpt from the NERC rules says the loss of load expectation should be the loss of load probability times the length of the period. My calculations says this is 2.4 hours per year. BC Hydro standards are also confusing, they say one day in ten years isn't 24 hours in ten years, it's something else.

There's lots of ways to do the modeling: deterministic, probabilistic, independent, meaning the hours are independent versus sequential, plants are out, they're at this hour, they're probably out the next hour, that kind of thing. These can give you all kinds of slight differences. Steve Stoft's book has a simplified model on page 138 that helps illustrate the overall problem. If you have a load duration curve and it's not price responsive, it's just there and your peaker is on the margin, you're going to have another peaker in order to avoid curtailment. Then the story is pretty simple. The notion that when you're setting the capacity you're doing something different than setting the duration or the value of lost load is an illusion.

They're all connected and the way they're connected is with the following equation. The optimal duration for curtailment is the peaker fixed charge divided by the value of lost load given that capacity and the load duration curve shown in Stoft's example. If we assume a peaker's fixed charge is \$65,000 per megawatt year, then the implied average value of the lost load associated with this one day in ten years standard (the 2.4 hours) is just under \$30,000 per megawatt hour. We'll come back to this shortly.

Generation capacity adequacy is strongly connected to transmission. The NERC long term task force has focused on available transmission capacity [ATC]. There are significant problems which include long term rights, order 888, and contract path problems. The ATC is not a well defined concept, you can't figure out what's the available capacity if you don't know how the system's going to be used, it's circular, etc.

These reliability models should make us nervous. In situations with multiple areas they attempt to figure out the interface capacity between zones and ten years going forward is. A contract path transportation model calculation is used to calculate the one day in ten reliability standard and what that means for capacity.

This is controversial since the ATC doesn't reflect reality. Consider the ISO New England testimony on their locational ICAP. They start by asking what the transfer capability is between two regions. Now, transfer capability has nothing to do with the transmission system (it's fine otherwise). They determine this capability by assuming first that the region is completely isolated and obtain an 8,500 MW need. Next, they assume everything is completely integrated and the transfer system is unimportant. Then it's 6,300. Finally, they assume it takes its share of the whole region in proportion to its load, then it's 7,900. The difference between 7,900 and 6,300 is 1,600, and that's the transfer capability. That's how they do it.

Another example is the PJM deliverability definitions. This is a little bit more complicated. PJM imposes a one in 25 year standard for transmission capability. They actually do model the transmission system correctly, unlike the New England example I just gave. However, they impose a very high reliability standard in the transmission system. This is to justify the simplifications they assume later in the generation portion of their regulations where they also use similarly inaccurate contract paths.

These are problematic definitions if you're thinking about how markets work. Calculating

long term transmission capacity is controversial. It is even harder in the reliability case to get long transmission rights. It may be that these ad hoc methods are the best that we can do. I don't have a better way to do the long term calculation. I can only emphasize that it's difficult to determine and define.

One solution is to change the market design so these problems are less necessary and less relevant. Let's return to the question of the implied value of lost load. Recall that the one day in ten years is approximately \$30,000. Somewhere in the 10 to 15 thousand range is probably more sensible. If we compare the current \$1,000 price cap in this scale with \$10,000 (or 15, or 30) there is an enormous difference between where we are and what we should be doing. All the problems with long term standards fade dramatically if it really is the case that sometimes the peaker is worth \$10,000 or \$30,000 and we're capping it at 250 or 1,000? It reduces the value of operation reliability just at the moments when you need it the most.

We should focus on that problem. It improves reliability if you get the pricing in the real time markets right. It improves operating efficiency. It makes the resource adequacy problem easier to deal with.

The final issue is administrative demand curves. You must set an administrative demand curve for operating reserves because it doesn't arrive from the market naturally. My comment on this is to get over it. There are no pretty solutions, so let's do it. Let's focus on the market failures, fix the market design, and get the prices right just like the engineers told us.

Speaker 3.

I'm going to discuss issues from the operating reserve side, particularly the New York ISO. Markets and reliability can work together, we can co-optimize different marketplaces to provide incentives that make operating reserves available when we need them.

I'll discuss NYISO reliability rules, a market overview, actions that operators take if the market does not provide the proper signal, ancillary markets, and what the ISO calls its demand. This is different from its capacity demand curve. There's a separate demand curve that sets shadow prices based on historical numbers for deficiency in certain locational reserve requirements.

The New York ISO is a single state entity. It's a highly divested, complex marketplace featuring co-optimization on the energy and ancillary markets. They will have about \$10 billion in transactions this year, about 40 billion since its inception. This includes New York City, a unique challenge. They're at the center of a lot of markets: the Canadians, both Hydro Quebec and the NEISO to our north, and PJM down in the south.

The ISO has three entities that establish reliability rules: NERC, NPCC, and the New York State Reliability Council. They become progressively more onerous as their jurisdiction becomes more local. Each incorporates the rules of the one above them. The New York State Reliability Council has very specific roles. This includes the thunderstorm alert. When they have thunderstorms entering the New York City area they redispatch the system and configure it for an N minus two condition instead of an N minus one on the transmission system. This does result in some pricing anomalies but the reliability criteria is very specific.

NERC standards sit on the top, then the NPCC standards which address the establishment of 10 and 30 minute reserves and also regulation reserves. The most binding of these is the New York State Reliability Council. For instance, they require that at least 15% of the ten minute reserves be synchronized.

The criteria in New York for a single line loss contingency is 1,200 megawatts with Hydro Quebec. New York is required to have ten minute spinning reserves of 600 megawatts, and another non spin of 600 megawatts. One half of

the size of the next largest contingency just so happens to be another 600 megawatts. They need 1,800 split between the three groups. If more ten minute spinning was available the that could make up for some non-spin at a lower requirement because fast reserves can be substituted that way.

New York uses security constrained unit commitment and scheduling. They co-optimize energy and ancillary services and produce an hourly locational price. The day ahead market provides a binding commitment for suppliers and load. All the install capacity suppliers are required to bid into the day ahead markets. New York's real time dispatch re-optimizes energy reserves and regulation on a system wide basis every five minutes. They have a quick start commitment of 30 and 10 minute resources. Locational pricing occurs at 5 minute intervals.

New York's ancillary services market is the only one to do co-optimization on a day ahead and real time basis. There are separate bids for energy regulation and reserves. An entity must bid energy and reserves to take part in the day ahead or real time market. The regulation market is optional. They can take higher quality reserves in lieu of lower quality if there is a surplus of bids. Reserves are committed on a locational basis within the state. There are a variety of constraint areas and ways that they cascade through them. The ancillary services are fully scheduled in the day ahead, and then rescheduled through the real time operations.

The New York operating group is the group responsible for the reliable operation of the grid and facility dispatch. They forecast and review all the requirements of the operating reserves on a real time basis. If the marketplace doesn't create incentives for units to come on line and be dispatched, they will take additional actions out-of-market that assure reliability.

There are several actions available for reliability problems. Supplemental resource evaluation is used to dispatch dispatching units with longer startup times than 30 minutes. If a deficiency in the day ahead market is identified, they may

start a unit to provide reserves that weren't committed day ahead.

They can rescind energy exports. They bring them to native load, re-dispatch the system, and back down on firm generation within the control area to provide reserves. Similarly, emergency imports can be scheduled. An import allows them to take one of the units and back it down to increase the reserve margin. There is also an emergency demand response program and a special case resource program. These demand response programs can reduce load and alleviate the reserve requirement. Finally, quick response voltage reduction relief is available (this is another name for load shuttle).

The overall software platform was recently enhanced in February. It provides a two settlement system for energy and reserves. This allows financial incentives in the marketplace that respond to day ahead and real time operation for energy reserves and regulation. When somebody is selected for ancillary services for a reserve, they're indifferent to whether it's reserves or energy. Usually our operating reserves are in the cents per megawatt hour (equal to dollars per megawatt month). They are not highly priced. If called to provide reserves the operating group will back down their dispatch and they receive their lost opportunity cost between what they're actually running at and the marginal cost. That goes directly to them. It doesn't set price, but it determines what the reserve cost would be in that case.

If an entity is called for reserve, they are made whole so that when they bid in they have no incentive to withhold on the operating reserve side. They'll bid in what they believe it would cost them, they'll bid in an energy charge knowing they will be made whole overall.

They can do this on five minute basis in real time. Reserve costs are calculated based on the shadow price and the marginal loss component of a unit that is called for reserves. All dispatch capacity is considered for scheduling as energy or reserves. There are also established demand

curves used during shortage conditions which set maximum prices. They are used if operators have to re-dispatch the system or entities are needed to bid back in for reserve shortfalls. The demand curves are based on historical analysis derived from past shadow prices or constraint relief prices. They are set as an upper limit.

In a shortage situation, that price is set by a demand curve and it's not necessarily smooth. It could be a step function. It shows the market that prices are in a shortage condition and that they are willing to pay more. The key objective is to schedule resources to meet the required reserve constraints when they're available. This sends the desired price signals when shortages occur. However, the demand curve does not limit actions that can be taken by the operator to create additional reserves for reliability criteria. If the market does not respond, the operator will take out-of-market actions to ensure reliability.

Let me put it in context. If they go deficient on 30 minute non spin reserves, they have four hours to return to compliance. However, the operating principle whenever they go into any deficit is "as soon as possible." This is the only criteria. For the 10 minute spin and non spin, the criteria set by the New York Reliability Council is 30 minutes for a return to sufficient reserves.

There is only a limited amount of time to solve a deficiency. At a 5 minute co-optimized basis, the operator will assess the deficiency, the real time dispatch, the commitments it's making ahead of time to ensure they are forecasting and recognizing a reserve shortage. They will dispatch units or back units to create or replace the reserve deficit. The operator isn't necessarily going to immediately take an out-of-market operation. They will allow the software to go through an iteration or two to ensure things are moving, that a deficiency has been recognized, and the right signals are being sent. If this isn't happening, the operator will move rather quickly. Obviously, reliability is the paramount goal, and they will circumvent the market to assure it.

Locational requirements complicate this. For instance, 300 out of that 600 megawatts of spinning reserve in the eastern constraint area has to be located on the east side of that constraint. Further, 60 megawatts of the 300 of the 600 basically have to be physically in Long Island.

New York has implemented a location pricing mechanism for these operating reserve requirements. Many of these price incentives are derived from the reserve requirements. For some areas the demand curve is substantially reduced from others because there is no requirement. For instance, in Long Island we're required to have 30 minute reserves, the 10 minute reserves have a substantially lower demand curve.

There's nine different demand curve categories. If you run into a reserve in any of these categories you revert to the demand curve. They set the maximum price that is paid for a bid from a generator or if the system is re-dispatched with operating reserve market. For instance, the ten minute reserve for the New York control is 150 MW. If they had a deficiency there and the ten minute reserve was needed they would dispatch a quick start unit or one that meet the requirement in time. They would back down another unit to create reserves if it was at its capacity limit. Remember that they would also make them whole. They'd provide their lost opportunity cost plus the \$150 a megawatt hour from the demand curve to provide the reserves.

The reserve categories are additive. If requirements in the New York control area were not being met they would be translated into the eastern side of the constraint. If requirements were not being met there, the price signal would continue to grow as the deficiency cascades through more control areas. Long Island is not included. It has locational pricing and an additive mechanism but never sets the state wide price because the facilities have a strong degree of market power. The state wide price is always set with the western side of the constraint.

There are other unique situations. Long Island has a \$300 price on 30 minute reserves. There are two main transmission lines for Long Island

and there is a 30 minute thermal limit on the line for overload. After 30 minutes it must be alleviated. The requirement shows a price increase when reserves must be re-dispatched or brought in.

Consider a shortage where there were not enough 30 minute non spin reserves in the day ahead or real time markets. Then the market would clear at the highest price – the last bid that they received. The entire operating reserve is moved to the demand curve. In this case, it would be set at \$50. That would signal others to bid additional reserve requirements. Otherwise the system would be re-dispatched to provide the shortfall.

Their experience under the demand curve approach demonstrated reliable operation during the record peak demand this past summer. There was a new peak just over 32,000 megawatts. The previous peak was 30,000 megawatts. They did go into deficiency at the 30 minute requirement twice. These lasted about four to ten minutes. The system got very quickly into sync. It went into the scarcity pricing demand curve and responded without going to out-of-market operations.

The demand curve allows for efficient integration of normal market scheduling process. If necessary, the operator always has the capability to intervene with an out-of-market operation to make sure that their reliability standards are met. The demand curves enhance reliability under the locational pricing operation by sending the desired pricing signals on a locational basis to indicate the shortage when the conditions are indicated.

Question: The prices in the demand curve are set administratively?

Speaker 3: Yes, they're part of their tariff. They're derived from historical values. They analyzed constraints from the west, east, and Long Island. They set values within five percent of the historical reserve clearing prices on an aggregate basis. If they find that the demand curve is not sending the right price signals they

can reevaluate and apply to FERC to change the demand curves. So far they've been pretty representative, they have seen the response they needed.

Question: Why is the 30 minute reserve so much in Long Island? \$300 a megawatt hour.

Speaker 3: This is directly tied to the line outage loss. If they lose one of those, they have 30 minutes in which they can overload one line. They only have 30 minutes to get something moving so we trigger high price immediately. This criteria is derived from the New York State Reliability Council. There's no locational requirements in the other time slots for Long Island. Low dollar values have been put in for them because they have some desire for a locational incentive but the real requirement is the 30 minute reserves. It could be supplied with the ten minute spin or the ten minute non spin but the higher price is only triggered at 30 minutes.

Speaker 4.

What's the definition of reliability? I spoke recently at a large industrial consumers group. The first question concerned updating standards in response to Hurricane Katrina. Tower strength and the length of time in which a customer should be out. What's the appropriate standard for when they should be returned to service? Reliability is any time customers don't have electricity; that's how they define it. It's more than that of course. I'm going to try to provide a framework for reliability standards so we can understand their impact on the market.

Much of what I'm going to discuss involves NERC standards. First, I have some historical events to consider. I have two groups of events to consider. Some time ago Rhode Island Hospital chose to use their backup generators full time and to dispatch them against the utility's rate. The first time they had their unit down, there was an outage on the double feed because of the way they had configured it. They had no power. The hospital spent 24 hours with

no power, somebody died, etc. That's a distinct form of reliability.

The town of Medford, MA – 6,000 people – had an underground cable that was too old and they were out of service. Tufts University was out of service, nobody was too worried. But boy, when the beer distributorship was out of power, there was a real problem. That's another form of reliability. In Lynn, MA all they wanted was to put their big old ugly transmission line under the ground. Every time the wind blew and somebody was out of power they would ask why all the lines weren't underground.

In London [UK], they had a relay failure that shut down the subways. It might have been an uneventful 37 minutes otherwise. The fact that the subways had decided not to have backup generation any more, and that London Electricity did not have a double feed to that location, was hardly noticed.

Finally, the northeast blackout of '03 can be considered. There's common elements to all of these. They're all considered to be reliability events, only the last of which is covered by NERC standards. Even London wouldn't have been covered by the standards if it had been in the U.S. They all involve regular, ongoing economic tradeoffs, but not necessarily the kind of market rules that we've focused on here. None of them is connected to resource adequacy issues such as reserve margins, LOLEs, LOLPs, etc. The problems were entirely different.

Let's consider the second group of problems. In the 1970s Dallas and Pittsburgh are playing football. It's 30 degrees, there are flurries, and the only problem is that this is Miami. Florida Power and Light had gone from a 6,000 megawatt winter peak to 10,000 megawatts the next year; a 60% increase in load. The estimated curtailed load was 2,000 megawatts was only 20%. This went on for a day and a half. That's resource adequacy. New England has seen this too; periods of time where they had interruptables, government buildings being shut down, employees sent home, etc. This occurred with a 5% increase from the previous year and

only 1% unserved or less. California had similar problems with resource adequacy although there are other views. This is all resource adequacy.

The two common denominators are resource adequacy and a clear set of economic tradeoff decisions being made. The economic decisions are not typically thought of as reliability events. Most of us argue the system worked like it was supposed to. You can't really discuss reliability, markets, and standards without making these distinctions.

One way to conceive of this is to think of a child attempting to build a nice square tower of blocks that stands perfectly erect, is strong, and is going to be there indefinitely. That's the steady state. One should be able to pull one block out from anywhere. It's important to remember that the NERC standards are only designed for the very bottom of the stack. That's all they're trying to do. There's all kinds of other reliability.

Answering the question of reliability versus economics is dependent on where you are in the stack. As a general principle, it's important to look at the economics higher up in the stack first. You should be more careful at the bottom.

I have a few observations and conclusions. First, reliability standards themselves were driven by interconnections. Those interconnections were driven by economics and markets. The NERC standards at the bottom primarily exist because of pre-existing economic concerns.

Nonetheless, the NERC standards are also driven by reliability crises. They're written in response to problems, often with a lot of energy, and very quickly. They're not derived from market crises, and don't often take into account economics. There's obviously market implications in the reliability standards we have today. We have to begin to deal with the implications of reliability standards even at the bottom of the stack.

I have three specific recommendations. First, start with resource adequacy, reserve margins, LOLP. It's more transparent, it's more regional.

There may be more bang for the buck, although that's not necessarily clear.

Second, get everybody who's holding hands to go ahead and dance. If we had more PJMs, New York ISOs, and more markets, then we would have the opportunity to get more economics out of the current set of standards. There's more that can be done with current standards to make progress without changing the standards.

Finally, one thing about the process at NERC that works well is that anybody can submit a standard at any time. There's a real opportunity to have new concepts evaluated. We can consider when we must step outside of the market rule and intervene, and determine whether the standard is inadequate. Are there ways to help the market do a better job more often? NERC is happy to consider them. There is a process to implement change.

Question: The NERC market interface principles include principle three: "an organizational standard shall neither mandate nor prohibit any specific market structure." This sounds harmless. Let's compare it to Principle two of the seven IEEE-USA principles: "prices of all market products must be established in a manner that provides proper incentives for reliable behavior." That makes a lot of sense. Here's their principle three: "incentives for effective planning ... should be incorporated into all market structures." That is also more useful. Is there a philosophical conflict between NERC's principle three and the IEEE principles? Should it be revisited to accommodate the incentive oriented aspect of the IEEE principles?

Speaker 4: The most specific example discussed is locational marginal pricing [LMP]. These signals would help instruct participants as to where to put their resources. Areas without LMP may be using TLRs more frequently. However, it is not NERC's task to indirectly direct how a market should be structured. The principle is appropriate to the narrowness of the task assigned to the reliability organization. They should work very hard to do all they can to support markets but they shouldn't define how

somebody should do business by the way they write their standards.

Speaker 3: As you have reliability standards you have the evolution of markets. Markets will evolve to incorporate certain physical reliability standards in their operation that reflect how they control their grid, dispatch, and energy in their control area. and the flow of energy across the control area that it has. Every market out there has a different structure so the NERC standards need to accommodate that.

The market evolution will address reliability and continue sending the right signals. IEEE recommends market products that provide incentive for reliable behavior. Locational pricing has done that. In New York there has been an improvement in forced outage rates on the supply side from about 12% down to 4%. This is a significant improvement. There are incentives for unit availability to meet the reliability of the system. It is working and it will evolve. There's probably other things that need to happen but I'm not sure that NERC is the right entity to apply a market standard. FERC would be that right entity. They regulate the markets.

Speaker 1: I'll make two quick comments. The biggest problem for IEEE was getting a consensus. The principles were for a restructured industry but they didn't want to be too prescriptive. They try to say you don't have to restructure, and to stay away from saying this is how you must restructure. They did try to establish compatibility but any further and they would have lost unanimity.

LMP is the right kind of example but it doesn't go nearly far enough in addressing reliability. It only addresses energy sources, not the kind of units or programs that might be needed to address reliability more directly, such as load shedding programs. Any favorable impact that LMP has had on reliability is at best indirect. If you have more generation in the right places, you're also going to have more reserves in those places probably. However, a more direct approach is better locational reserve pricing and

very high valuation of reserves. These provide a better market design.

Speaker 2: You can't have a system without some kind of principle standards. However, the one day in ten standard is not a NERC standard. Most people think of it as a NERC reliability standard, but in reality it's different in every NERC region. Even some utilities do different things. That standard is not a basic principle standard that sits on the bottom block. There has to be some way that the bottom block ensure there is enough installed capacity.

Speaker 4: You got it exactly right. They have a standard that says you have to have a standard which guarantees that. It allows for different ones.

Speaker 2: Well, that's a good defense if you're the head of NERC. However, other standards have to go further. When we go further and create a one day in ten years standard for installed capacity, this implies standards that may be inconsistent with certain kinds of market designs.

More detailed standards have to go further and they're technically not NERC's responsibility. However, they're certainly part of the larger picture. Once you make these decisions they drive a logic that results in bid based security constrained economic dispatch.

Speaker 3: Cascading standards can work. New York has the NERC standards, the northeast power coordination council – it has the one day in ten – and then the New York State Reliability Council overlays a locational requirement. New York has a locational capacity market to send the market signals for capacity where it's needed. They have standards that cascade all the way down and provide what they need from a resource adequacy and a reserve standpoint.

Question: My original question really concerned whether principle three needs to be rewritten to say that standards should work to reinforce reliable planning and operation of the electric system. This is contrary to the way it reads now.

It doesn't discourage bad markets nor encourage good ones promote reliability.

Speaker 2: You mean standards should be written to promote market structures that reinforce reliability solutions?

Question: Yes, that's correct.

Speaker 2: Not that standards should be written to promote reliability because that's already the case.

Question: Right.

Moderator: Here is a quote from the Energy Policy Act, section 1211. It describes the Federal Energy Regulatory Commission's role in the ERO [energy reliability organization]. The commission shall give weight to the technical expertise of the ERO ... but shall not defer with respect to the effect of a standard on competition.

Question: Several people have discussed the value of lost load. It's one of the most difficult things for the industry. One alternative was an over/under approach for resource adequacy. This indicated that the value of lost load was derived from how much installed reserves you really should economically have. It seems to balloon. Can we get a better answer than 15 to 30,000? Especially when companies have to go to state regulators to pass through those costs of the capacity.

Speaker 2: The value of lost load is critical; it does drive a lot of these things. At a minimum, it's two or one order of magnitude higher than the current limits. That's the true part of the story.

More importantly, if people actually faced the possibility of those kinds of prices, other kinds of responses other than just putting in another peaker would emerge. You don't have to get the value exactly right. If you make it \$10,000 or \$15,000. The demand curves won't maximize zero spinning reserves at \$500, they'll go to zero spinning reserves at \$10,000 and then you draw

a line between. Lots of times we'll be on places in between.

Lots of responses will emerge between 500 and 10,000 that can actually be done. You won't ever end up equilibrating at \$10,000 because the marginal thing will not be a peaker with a \$65,000 megawatt year requirement. More likely is some kind of demand side response. These are more expensive in the variable cost component, like \$1,500, but they're almost zero fixed charge component, so they don't have to do it very often. So the prices won't actually get that high. Just make it \$10,000 and see what happens is my recommendation. We don't actually need to know whether it's 10, 15 or 20. It's never going to get there very often, if ever. All other kinds of things are going to happen. Further, it will simplify all kinds of other stuff. We don't actually need a very precise estimate when we're off by two orders of magnitude.

Speaker 4: The use of one day per year or one day in ten years isn't precise either. However, it's fine. It is critical to get that into all the reliability planning. We need to get everybody to accept that as a legitimate concept.

Speaker 2: My strategy is relentless repetition.

Speaker 1: This is a jurisdictional problem too. Many state legislatures or public utility commissions want to set flat rates to protect the consumer. Flat rates mean there is no incentive at the consumer end to save or to have demand managed programs. It's important for states to help enable demand response. If you get to the 10,000 mark, people will respond. It won't happen with the present rules and levels of compensation.

Speaker 3: Price is political. I don't know of any other commodity that has a political cap on it but we do in electricity. The conventional wisdom is to send those price signals. The political reality is not so easy. A bridge between the two has to be found.

Speaker 4: If we could plot for regulators their acceptable range on electricity versus other

things they regulate, like natural gas, we'd get staggeringly different answers. The idea that prices could change 5 or 8% in electricity is considered outrageous. However, gas prices just changed 40, the world didn't come to an end.

Question: We've been talking for 11 years about aligning spot prices with the true value of power, first in congestion management and ancillary service, more recently in the resource adequacy and system reliability context. However, a large part of the industry just will not mentally engage on this issue. They are captured by the mantra of low prices, happy regulators. They can't get past the idea that low spot prices are somehow good for consumers.

California was the quintessential example of this. Almost everybody was in the spot market and things really spiraled out of control. FERC was primarily trying to dull the prices. Now mandatory forward hedging of price and supply risk is changing the California market. People are seeing that if they're hedging risks, then the volatile spot price is not a threat to consumers. It can be a threat to suppliers who are short with forward contracts but there's no reason for consumers to be negative on volatile spot prices. I've concluded that it's a deficiency in market design if there is not mandatory forward hedging by load serving entities. Do the panelists agree?

Speaker 2: From the beginning, many of the critical issues in market design were how to facilitate forward hedging. This is where financial transmission rates came from. They've always been a central focus, the only question is the mandatory part. It's probably much better than other kinds of solutions. It's a good idea as part of this market design. If there were a state that didn't want to do it and to let it rip instead, a sort of Texas approach, then they may be making a mistake if they really mean it. It's tough to follow through on that.

If you go to mandatory, how long is long enough? Do you need 5 years or 20 years? I think you can make a case for a three year story.

Speaker 1: A major problem preventing the natural development of long term markets is regulatory uncertainty. People don't trust that three, five, or ten years from now their product will be worth anything because regulations can change any time.

Question: The first speaker was describing huge swings from an on peak to an off peak period or vice versa. The ramping problem has a different context. This occurred at the west FERC NARUC joint board on economic dispatch meeting in California. A Cal ISO representative was concerned about ramping that occurs at the top of the hour when short term schedules are redone. There are entities from out of state, or non-FERC jurisdictional units, within state, that suddenly change what they are willing to flow into or take out of the ISO. These create of swings of as much as 4,000 megawatts. Are their fundamental ramping problems involved with jurisdictional problems? The lack of standard markets and seams problems between markets in the east both exacerbate this. Are there fundamental reliability solutions needed to eliminate these concerns?

Speaker 1: So, the seams issue exacerbates this problem of ramping. Within one market you can use a market mechanism to purchase more regulation capability, but not between markets. The biggest problem we face as a nation is the seams, particularly incompatible seams. The level of coordination between MISO and PJM is a good example of how to address this.

I use an FAA analogy to describe the incompatibility. If an air traffic controller in St. Louis had a different set of altitudes than Chicago, the minute those planes cross the boundary everybody has to dive 500 feet. This is not a very good design.

Speaker 4: There's a distinction between the west and east examples, though. In the west there were difficulties in implementation but they probably knew what they were supposed to do and were having difficulty doing it. The problems for the operator in the east is that

schedules have probably been put in incorrectly. They're very different, and both are important.

I'm unsure about the proposal that operators ought to be double Es [engineering standard]. I'm not convinced that we want to mandate that we can't have anybody be an operator who's not a double E.

Speaker 1: I actually didn't agree with that solution. Instead, having a double E available that the operators can call if needed is very important. Most European systems have that capability 24 hours a day.

Speaker 3: A localized problem is generators not following a dispatcher or being able to ramp up. Operators send out signals and generators respond with "persistent dragging." They won't ramp up because it costs them money. It's a real problem for the operator's regulating units. It's a problem for participants because the generator that is ramped up is getting penalized and the other guy's just sitting there real happy. There's no mechanism to penalize them for that. Generators complain about operator attempts to fix this problem but it's their group that's causing it.

Moderator: Is this kind of problem that's appropriate for resolution at a regional reliability council if it's causing reliability problems? Ramp rates and generation?

Speaker 4: That requires a global answer. There needs to be room for regional solutions. However, they can't be arbitrary and need some consistency with their neighbors. You can't put one's neighbors' reliability in jeopardy from having done it. Often, tailored solutions are what are required because the actual standard is quite broad.

Question: On one hand, NERC is trying to set a minimum standard that enables everything else to happen. It might be quite appropriate to have minimum standards for things like 60 hertz, protocols between control areas, and a requirement for a planning standard; but overall these are not invasive. It's a minimum standard

philosophy. Yet speaker 2 was unhappy because he couldn't find cost, couldn't find this or that. I can't tell if minimum standards are a good or bad thing. FERC is moving forward with an ERO [electricity reliability organization], and many still believe markets are appropriate. How do the standards work with this in the future? How do we keep the lights on and have the markets work?

Speaker 4: The tower analogy I used earlier argues that there's a necessary foundation. FERC has said, and we hear this in the provinces in Canada, that that platform should be the same everywhere. If the fundamental tower you were building didn't have the same number of layers and supports all the way around, it wouldn't work.

New York has said they're going to build a higher tower with a bigger base all together. They need more at the bottom. They're not putting a layer above that's different from everybody else. They're expanding with a bigger base, stronger rules for themselves, a base that's larger because their tower is real big. They have 100 story buildings in the city and you don't want to be stuck in one of those elevators.

NERC has to find a place to logically stop. It's a matter of finding the right place between being prescriptive and allowing market openness. The base needs to be consistent, strong, enforced. It needs to be flexible for regions where it needs to be greater. From that point up the market should be stepping in to balance it all as effectively as possible. There's always room to ask whether NERC is writing standards in the most effective way.

Speaker 1: I have a different take on that. Markets are not separable from reliability rules. If you try to separate them, they're going to fail. Markets are very conscious of the reliability environment in which they're operating. Rather than thinking that NERC has to cover every base, a better way to do it is to give as much guidance to the market's design as possible. You will end up with a good market that will make the need for utilizing the stick a lot less frequent.

While markets may do most of the job, we still need NERC as a backstop to make sure the system doesn't fail. Finally, in creating the rules, it's not a matter of more rules. We should have better rules, not more rules.

Speaker 2: This is a really important issue. One way to interpret the market interface principle number 3 from NERC – the way it's written now – is to be highly restrictive of what NERC can do. Their rules must stay general to avoid impinging on which kind of market designs are possible.

This is consistent with some of our speakers. There is a fundamental problem. The new law says that the ERO requirements will be mandatory. The ERO, will probably be NERC incidentally. What about the other regulations? If we're going to have this restrictive definition that the ERO can only oversee the basic, small base and that's the only thing that's mandatory, then everything else is not mandatory. How do we handle more specific reliability requirements that won't necessarily be mandatory?

My initial view was that the standards we really need, the larger base, would prohibit certain kinds of markets or support others. If you turn it on its head, where does the authority come under the law? Can FERC mandate, or do we have to change the law? It's a conundrum.

Speaker 4: I expect FERC will allow a region to expand the base because they want something stronger. Those standards will make their way to the ERO from the region. They'll make their way up and get endorsed by the ERO, approved by the FERC or a province in Canada, and become part of the mandatory enforceable system.

Speaker 2: As region specific?

Speaker 4: Yes. That part will work. The implementation of that should be market driven as much as possible. That's not inconsistent. However, NERC's view is to build the strongest base possible across all the market structures that exist. That's the mandate today.

Over time that will change. Currently, expanding that regulatory base for regional differences is entirely possible.

Speaker 3: There were specific carve-outs in the energy policy act for New York.

Speaker 2: They were very specific, not generally applied.

Speaker 3: That's right. Certain New York specific standards could become mandatory there without ERO or FERC oversight. They would be enforceable in New York under the act. Generally, a region would have to come to the ERO with a regional standard, get it approved, have the ERO bring it to the FERC for approval as a regional standard, and then it would become mandatory under the Federal Power Act. I expect the process will be permitted and rules developed for creating a regional standard.

Moderator: NERC has this building block concept. These standards are often broad but in some cases they are very specific. Even in those cases where they're broad and left for the interpretation of a region, there is a routine audit process where NERC, audits the effectiveness of the interpretation of that standard. In the last audit, FERC joined that audit. There are controls even on the broad standards.

A separate question; do market participants participate in the standards development process?

Speaker 4: They certainly participate. Further, when a reliability standard comes to the commission from NERC, it should pass the FERC's (or a province's) test for being fair and non discriminatory with respect to competition. The NERC process allows for all viewpoints to be heard, though that's not their primary responsibility.

Question: I'm trying to clarify some semantics between security, reliability and adequacy. Most NERC standards emphasize having the system operate in a secure manner in an operations

context. Many reserve adequacy and operating principles issues belong in a system security context. Reliability is the expectation of a system operating in a secure mode keeping the lights on. It's also the future expectation to have no outages in the system. Adequacy generally defines expected reliability. Most NERC rules emphasize operations and the secure operation of the system.

On the reliability side, NERC requires a standard for adequacy, something like one day in ten years. They could easily stop at that. That adequacy could be achieved by having more reserve margin, by demand side management – you could have it in many ways. That's where the markets come in. Markets have a bearing on adequacy. Some ways to achieve adequacy have better economics than others. This includes fundamental issues such as resource diversity, diversity of fuels, demand side management, things like that. We should conceive of security versus reliability versus adequacy as three related but separate buckets. Can the speakers comment?

Speaker 1: Economically, what drives the future's prices is the real time prices. I'm concerned about setting up markets before we have the real time prices right. In other words, the security should drive the reliability standards which should then drive the adequacy requirements, not the other way around.

Question: That doesn't contradict what I said. Reliability is an expectation that even if you're doing everything in terms of security, you will still have N minus three outage perhaps one day in so many years. It's a function of your future expectation.

Speaker 1: Yes, but we need to work with a real time system that recognizes the value of reliability. The value and parameters that you want for reliability in the day ahead will be established and from there we derived standards. It won't look like a day in ten years, but it is equivalent to it. It's the way we design the rules and expectations that needs to change.

Question: You don't have a real time system unless you plan for it. There should be stringent rules to operate it, but it's a connected issue. You plan for the system, you have the system, you operate it under secure rules.

Speaker 1: I don't think you plan it. We set up the rules so the market plans it exactly as we want it but we don't impose it.

Question: That's a change in game. Historically it has been planned and then operated. What we're trying to do is change the game so that the market does a lot of the resource allocation.

Question: We've heard that we need to retain the ability to have TLRs as a last resort. Is transmission maintenance, and criteria for TLR implementation, part of NERC's basic tower? Should they be there?

Second, since these are real time decisions, who's going to make them? In a region where there is an RTO it may be an easier question. In a region with no RTO, there are competitive issues at stake. These criteria could be applied by a non-neutral market participant.

Speaker 1: A TLR is nothing but an intelligent way of looking at a system and deciding the curtailments that are most effective to relieve a problem. If you have a good market you wouldn't have the problem in the first place, but it can always happen. There's always a need for intelligent guidance for the operator. In a real pinch, an operator should have the ability to go around the TLR and simply shed Cleveland for ten minutes rather than bring down the entire eastern grid.

In an RTO this problem is a rarity. A PJM operator has said that the toughest thing is to sit and wait when a TLR is being called and not push the button. Instead, wait for the market to respond, because it will respond 99% of the time. TLRs are certainly necessary for seams situations, RTO or not.

Ultimately any decision that involves curtailment will be done by the operator. They

have full authority to do so. Period. No questions asked. However, if the market design is such that it's perfectly compatible with the operator's objectives then it makes their job easier, and reduces incentives for that kind of behavior. In an RTO this structure is in place. In a non RTO the operating protocols and dispatch need to be implemented in a reliable economic manner even though they are pricing the signals. TLR should be the exception, not the rule.

Question: Certainly TLRs are the exception. Are the criteria for TLR usage so difficult that they should be part of the minimum standard, a national standard?

Second, in a non-RTO where the system operator is a market participant, how do you effectively police that, especially in real time?

Speaker 1: Should the TLRs be part of the minimum standard? The way they exist now, they're a bit of an overkill and they're open to gaming. An operator needs the tools to do intelligent shedding when the situation arises. Somebody needs to assess whether TLRs are the best tool. The question should be revisited; I'm not answering yes or no but rather that the problem should be assessed.

Let's consider RTO versus non RTO. The NERC minimum standards should apply to everybody and they are the backstop. In a non-RTO traditional system the same should apply.

Speaker 4: A tool is necessary and it should be part of the base. If there's better tools they should be implemented in the standard.

Question: I want to return to the value of lost load and the optimal reserve margin or reliability criteria. In my region there is a lot of commission mandated DSM money. The utility wanted to spend it as usefully and did a survey of customer outage costs in their territory. There isn't a monolithic standard because there isn't a monolithic answer to outage question. It's different whether it's residential, commercial or industrial; urban or rural; it's different based on the notice period, outage duration and the frequency, everything. There's no single answer.

It's not the same demand curve for reliability in the marketplace.

However, you can estimate it by segments. Pick a number and plan and say if it's worth \$5,000 a megawatt hour to an industrial customer we're going to use that, what does it cost to do it? You put it in balance and that ought to be the answer.

Second, once you do that and we get rid of the price cap, who sees that price? It's good if suppliers see the price. The units move if you're paying them a lot more money. You may get a supply response well before the \$10,000 number and that's a good thing.

As important as supply is, we need demand response. Customers have to be in the market or it won't work properly. If a utility with a monopoly obligation to supply no matter what it costs it leads to a market failure and political situation which is going to lead to price caps that no one wants.

When we de-integrated this market we lost entities which were designing these kind of reliability differentiator products, variable pricing for retail customers. Utility operators had to get out of the markets. Anything nifty clever they wanted the market to provide. They didn't want the ISOs to have a stake in the market, or to implement a program that would cut the price.

Initially, the ESCOs and marketers didn't have the sophistication, knowledge base and maybe the market wasn't mature enough to create reliability products. There was a deadly combination of a new market, people on variable pricing, and bam, they're hit with extremely high prices before participants can adjust and adapt. Why did we put the little guys into the market? We should put the big guys in the market because they asked for it.

At TVA, they're trying to clean up their old portfolio of interruptible rates. They were really economic development rates. They're trying to get real reliability; interruptible products based on the value of reliability. They are trying to market new products. A lot of customers don't

want to be on hourly prices now because of the price of gas. The new products say, look, if you'll be willing to let us interrupt you, or not interrupt, 12 times a year we're going to call and you're going to get posted a market price for eight hours. You can pay it or buy through.

These deals are a compromise to get price responsiveness from some of the largest load. The suggestion to let the price go to \$10,000 may not get a response fast enough in a time frame that will withstand political scrutiny. Especially if you're in California and a hydro problem where 20% of the capacity is down due to weather.

Speaker 1: Something like this happened in New Zealand. All of a sudden reserves were being valued at high prices. One of the distribution companies began bidding load interruption and accomplished a lot. It resulted in more sanity for the reserves market in New Zealand. This was exactly the demand response we've been discussing.

Speaker 4: First, a lot of demand response has no direct compensation. They make a public appeal and get 300 or 500 megawatts; it's already built into the plan. A program like this doesn't do that much new, people already demonstrated their capability to do it, like state folks, state office buildings.

Second, the LICAP and PJM proposals separate out the capacity side that way. This doesn't provide any opportunity for people to provide a response product.

Speaker 2: It's desirable to do everything the speaker said. It's not necessary to do it before you go forward because that actually paralyzes the process. We don't want to get caught in the trap of not doing anything until we have everything.

Question: We don't have to have it all right at the get-go. I'm more concerned with what do we do next. If getting rid of the price cap is so important, how do we do that? We have to live

with the reality that politicians are worried about getting burned at the stake.

Speaker 3: In New York, the operating reserve demand curve has a \$500 value cap for the ten minute spin in the overall New York control area. That is the clearing price for New York's special case resources. This is a demand program that buys ahead at \$500 a megawatt hour and is available through the summer. It mirrors the operating reserve side of the demand programs.

Question: As an aside, we should do a segment on the relationship between intelligent shedding and intelligent market design. PJM has been addressing the fact that they really can't separate markets from reliability, they have to work together.

There's a lot of players in this game. The ISOs, control area operators, the states, NERC, and the regional councils. It's tricky to sort through the different legislation. Is there a regulatory path that makes sense? Otherwise they're all stepping on each other.

Maybe we ought to focus the standards on the *what*, not the *how* of reliability. This means dealing with issues like frequency, or overloading of lines but being very clear that implementation is left to the control area operators. The standards should be performance based, not action based.

Finally, since the standards have to be international, make them market neutral. Separating the what versus how removes NERC from implementation, could keep standards performance based and may be the only way to sort this out and not step on somebody's toes along the way, while still giving operators clear guidance. Comments or thoughts?

Speaker 4: To the extent it's possible this is a good thing. It's like with trying to raise teenagers, the more you get them to do the right thing from a general description, the easier it is than a prescriptive approach. The challenge is that the previous regime, was more voluntary and currently the new law requires a mandatory

approach. This is a problem because if we make something mandatory then the operators have to know exactly what it is they're supposed to do. Even the current standard for black start, thou shalt have a plan and take it from there is not enough. NERC has been told it's too vague and won't be enforceable going forward.

the regulatory process would have been much more vague. In nine months it will be much more structured. There's a challenge between an open ended process at NERC but also a need for specificity that's going to enable them to be able to perform.

One change is there's a new desire for participants to understand what they're doing. They have treated the standards for a couple of years as if they're mandatory. However, the change in the law will put the standards into a whole new category. Clarity is needed. A utility knows where to go and who to talk to with an OSHA violation or an EPA violation. Further, the results were usually clear, and unpleasant. However, if an operator had an untrained operator but no NERC standard some time ago,

Session Two. PUHCA Repeal:

Should repeal proponents have been more careful what they asked for? Or will market and industry structures become more appropriate to contemporary circumstances? The repeal of PUHCA has led to at least two very divergent views of what will result. While there are clearly many shades of differences in between, at the poles the two views are as follows:

A. The repeal of PUHCA will remove arbitrary barriers to an industry structure more suited to the competitive marketplace that electricity has become. Many synergies and efficiencies that were institutionally discouraged, if not barred, under PUHCA, can now be achieved. U.S. utilities will now have more freedom to invest abroad and in more distant, non-contiguous regions of this country than they previously possessed. More capital will be attracted into the power markets as more investors, foreign and domestic, will find fewer barriers and disincentives to invest.

B. The repeal of PUHCA will change little in the scope of regulatory oversight, other than to move the forum for exercising jurisdiction away from the SEC and more toward FERC and the states. Mergers and acquisitions will continue to attract regulatory scrutiny, only in more forums and with less certain outcomes. The constraints on corporate organization, relationships, and governance may change to some degree, but not to the extent envisioned by the most enthusiastic supporters of PUHCA repeal. State regulatory concerns, and perhaps FERC's as well, about cross-subsidies, affiliate transactions, local control, and financial soundness will if anything be enhanced by the absence of SEC supervision. Moreover, the relatively lax administration of PUHCA in its later years by the SEC, may cause the post-PUHCA world to be more regulated and less attractive to investors than the repeal proponents envisioned.

Which of these visions will turn out to be the more accurate? What will be the real result of the repeal of PUHCA?

Moderator.

Obviously, Congress has finally repealed the act. However, we don't know what that means. Even

the leading advocate in Congress has indicated a concern that FERC is reinventing PUHCA via their rules and their new jurisdiction. A lot of states are looking at this question. This panel won't revisit the Congressional debate but try to determine what's going to happen, or what should happen, at FERC, at the state level, and what utilities might wish to pursue.

Speaker 1.

Wall street, utility analysts in particular, spent time from the late 90s to 2000 worrying about mergers, acquisitions, and non regulated businesses. PUHCA was an important part of that.

The PUHCA repeal doesn't do a whole lot. For the most part it just changes the venue. I haven't talked to one company that really thought that PUHCA was a constraint on what they wanted to accomplish. There are a few companies who indicated they would like to see PUHCA repealed, but it's generally just one of those regulatory hurdles that need to be accomplished to finish a merger. It's occasionally limited certain companies from doing non regulated activities. Overall, it's really the states and the FERC that were the primary hurdles for companies. For non-regulated deals, they sometimes worked out arrangements with the state.

PUHCA repeal creates new venues for how PUHCA gets done at the state level and FERC level. Conventional wisdom on Wall Street is that PUHCA repeal will lead to a lot more M&A [mergers and acquisitions]. M&A analysts and arbitrage specialists I know seem to believe that PUHCA repeal will lead to a lot of activity but I don't agree.

Utilities do mergers for a finite number of reasons. A good example recently, is Duke Synergy. Management changes are a key issue. A company is being acquired and may have older retiring management, need more depth, looking for a senior industry leader, or they're just playing shortstop on the softball field.

The second reason is growth. In the late 90s, early 2000s, companies were trying to keep up with the Joneses. They were making predictions about improved long run growth rates in utility earnings. Mergers were designed just for that purpose, or to take action if they falling behind on their promises to the Street for growth.

Third, mergers occur when companies are in distress or have gotten cheap for various reasons. This doesn't happen often even if we've had a lot of distressed companies. It hasn't led to a lot of M&As. Companies are leery of acquiring companies in distress.

Four, the all inclusive "strategic reasons." Whenever a company professes strategic reasons for a merger the Street can be skeptical. There are a few reasons why a "strategic reason" might make sense. Company size or the makeup of the company in terms of generation or customer type.

Deregulation is also an issue. Companies felt they wouldn't compete well in deregulation, or that their company was changing significantly because of changes in the industry. It led to perfectly legitimate reasons for mergers, generation with generation, distribution with distribution, this type of thing.

Diversity is an issue. Companies have different types of environmental issues, geography, different types of risk. Analysts like to see balanced types of customer classes. Some utilities are heavy on industrial customers, others are heavy on commercial; that's a merger that's good because it gives a balance to the company.

Wall Street only accepts mergers for efficiencies, synergies, or combining contiguous utilities to save money. The onus is on FERC and the states to do the same things that part of PUHCA did. State oversight will be particularly important. They are already responding to anticipated or proposed mergers. As consolidation increases it puts greater stresses on the states, from our perspective. There are instances where reliability suffers, or is perceived to suffer, because of M&A. Politics, job losses, utility contributions to the local

community are all important to state regulators. Obviously, the simple things like customer service or reliability are a key priority for regulators. Scrutiny from the state level, and to a lesser degree from FERC, probably balances out what PUHCA was accomplishing.

There are two principle issues. First, utilities want to find other places to put capital. This is slightly easier, certainly on the federal level. More state restrictions will probably soon make some M&As tougher. New Jersey has already set a standard for increased scrutiny and the Exelon merger. That may become a model for other states. There's plenty of scrutiny to go around. Most mergers in my experience have been tripped up by state and local entities.

Second, I am interested to see what happens for non regulated businesses. Currently analysts are skeptical of how utilities will do with non regulated business. There are few success stories. A couple that are excellent and a few that are pretty successful not overall.

Generally, these two issues may see additional state meddling. That's simply the perspective of Wall Street. Regulators are generally seen as a stumbling block to mergers although certainly they have a very important role that won't dissipate.

Speaker 2.

I will describe how state commissions are assessing the big picture question presented by PUHCA repeal. They are asking what type of company they want serving the state and what kind of regulatory review they want for the entry of such a company. Prior to repeal, there were restrictions on who could enter the industry, what corporate form, and what kind of debt equity ratio. Those restrictions have disappeared. For states, what do they want to invite, what do they want to discourage, and how do they achieve these visions? What is the state level regulatory policy that best aligns state interests and their legal obligations with the

interests of companies that want to change their corporate plans?

For 70 years, PUHCA has constructed that alignment in ways that have been inconvenient to many. How do we get a new alignment that doesn't cause extensive confusion? There are now 51 different fora answering the same set of questions.

PUHCA was originally created to address Congressional concerns concerning market power, diversification risk, distant management, securities abuses, corporate complexity, concentration of political power, and the ineffectiveness of state regulation. The statutory technique for addressing those was something called the integrated public utility system.

Overall, the integrated public utility system's standard was simply if you're going to collect corporate assets in the electric or gas utility industry they must operate together reasonably efficiently. You couldn't have a California utility owning a retail utility in New Jersey. There was a geographic and operational restriction, also a set of business restrictions, financing reviews, and prohibitions on inter affiliate transactions.

Investment by utilities and non utilities were restricted. Ownership by non utilities of utilities was largely prohibited. Inter affiliate transactions of finances, goods and services had limits and prohibitions.

For states, it helps to look at the original PUHCA standards, to get a better sense of what they want to do moving forward. Standards for acquisitions had a general principle. Acquisition could not tend toward the concentration of control of detrimental public utility companies types. Concentration of control was not inherently bad, only detrimental concentration. Clearly change had to occur; economies of scale, and of scope change. The statutory language defines three types of interest: public, the investor, and consumer. The act had an overriding concern that if you were small, you were vulnerable. This meant that both investors

and customers were classed in the same protectee category. Today, we're always thinking about shareholders versus consumers. The early idea of responsible corporate structure was to link the needs of investors and consumers.

The second criteria for acquisitions concerned the size of the purchase price. Was it fair in relation to the sums that you're going to be earning? Was there undue complication in the capital structure; anything generically detrimental to the public interest? An important one was section 10C2: an acquisition had to serve the public interest by promoting the economic and efficient development of an integrated public utility system. This was to ensure that holding companies which broke up didn't grow back together again in irrational ways.

Next we can consider utility investment in non utility businesses. This was completely banned. You could only own a non utility business if it was serving a utility purpose. If you were a coal burning utility, you could buy a coal subsidiary. You couldn't buy hotels, restaurants, GE, that sort of thing. A smaller utility could buy non utility businesses, but had to show they weren't detrimental to the public, investors, or consumers.

Another area of significance relates to issuance of debt and equity. There were six standards for any issuance of debt and equity. These only applied to major multi-state holding companies. These are the six: Not reasonably adapted to the security structure, not reasonably adapted to the earning power. These were to avoid excess leveraging, people borrowing more than they need to service their business. Three, you shouldn't be borrowing big dollars to go into unknown areas. Fees and commissions should be reasonable. No improper risk. And finally, no detriment to interests of the public, investors, or consumers.

Let's contrast these with securities review at the SEC. People often argued PUHCA was redundant because SEC acts regulated security

issuances. The difference is one of disclosure versus wisdom. The SEC acts aim at accuracy in disclosure of facts relating to issuances.

The burden on the states may be most significant here. FERC jurisdiction over securities issuances is limited. It's under section 204 of the power act and it's in effect a reverse preemption. FERC has authority over utility issuances of securities only when states do not, and that's only a handful of states. States who have been routine about security approvals because the SEC had oversight will have a bigger task to review the nature, type, amounts, and purposes of security issuances.

Inter affiliate transactions are probably obvious. This was always a question of milking. Is there an excess dividend payment from the utility to the holding company? Is there a guarantee of holding company indebtedness by the utility, or guarantee by the utility of non utility debt? These are gone now.

How much of this is now replaced by FERC regulation? It's a bit of a mystery. FERC's got a proposed rule out and they're taking a lot of blows right now. I'm not sure where it will come down. However, there has been a substantial expansion in FERC authority. In section 203, the FERC's mergers and acquisitions statute, FERC had oversight for anything over 50,000, now it's ten million. Further, a public utility acquisition of another public utility's stock is now subject to FERC review. Same for acquisition of an existing generation facility, because of Congressional concern for concentration in generation markets. Finally, if a holding company acquires a holding company of a similar structure then FERC reviews it. FERC doesn't have jurisdiction over a utility acquisition of a non utility business or vice versa. There is no SEC review anymore either.

There's no Congressional attempt to prevent state enactment of statutes similar to PUHCA. This is an important consideration as we discuss what states might do now.

Typically states don't think about merger policy if there's none pending, and then they have one and they're too busy dealing with the proceeding to create a solid policy. After 20 years this problem, I'm trying yet again to focus the states on the creation of well thought out merger policy ahead of time.

There are major categories of corporate events to consider. Utility mergers with other utilities, either operationally integrated, you know, next door in the same power pool, or not operationally integrated like a California, New Jersey utility. Next, utility acquisition of non utility. They can do it for utility purposes like a coal based utility buying a coal company, or you're completely diversifying into new areas. The non utility acquisition, the Warren Buffet type acquisition. Maybe the acquirer has an operational relationship, a lender who wants to acquire a utility, or somebody's just building a diversified portfolio. There's also inter affiliate transactions of goods and services, financing transactions and debt and equity issuances at the holding company or at the utility level, for either utility or non utility purposes.

There are a variety of reviews, limits or conditions that states can implement. An example (I'm not advocating this) would be the Wisconsin Holding Company Statute that says diversify as much as you want but the limit is 25% of the total holding company assets. It's a permission to do what you want as long as the pain from failure is limited. These are the kinds of things states will be asking.

A key issue is whether there is an orderly way for that discussion to occur? Several people have a sentiment that says just let things run, especially in the industry. Just let the states do what they want on a transaction by transaction basis. Alternately, some states are considering entire rule investigations to set coherent standards in advance of M&As. Others say let's come up with standards as individual cases come forward.

The related question is how do the states come together and do this on some kind of semi-

orderly consistent basis. There is a real economy of scale associated with states doing this together. Some entities that don't like what the states will do would rather not have them all come together. However, in terms of the predictability on Wall Street and saving regulatory resources, it would be a lot more orderly for the states to come together with some kind of common ground. The debate over the last 25 years always centered on whether someone supported PUHCA or not. There was never a rational debate about a regulatory mechanism that's most livable for all sides. There's real resistance to that same conversation now. I'm concerned that another 10, 15, 20 years could go by where we lose real economies from transactions. I recommend that we try to focus on an orderly process for determining policy.

Question: Are there any issues for states or holding companies in terms of foreign companies making acquisitions in the US?

Speaker 2: Under PUHCA a foreign utility company was still subject to the same integration standards. For example, when Scottish Power purchased PacifiCorp, it was held to the Holding Company Act standards, but it wasn't banned on grounds that Scottish Power was not integrated between Scotland and US. It was subject to integration standards with respect to internal US assets. With repeal there's no standard whatsoever. At the state level I don't believe there are any statutes that differentiate between foreign or not.

Question: Doesn't the repeal provide more of an opportunity to invest abroad by US utilities?

Speaker 2: Yes. Prior to repeal if a US utility company tried to acquire a foreign utility they would have an integration standard problem. After 1992 FUCO, the Foreign Utility Company treatment, allowed for that.

Comment: Under the new 203 amendments a US utility foreign acquisition is now FERC jurisdictional. It's even arguable, because it was so poorly drafted, that if a foreign utility company at a holding company level buys

another foreign utility, is under FERC jurisdiction. You could have the situation where if two foreign utilities merge their holding companies and have US operations they will be under FERC jurisdiction and require approval. It's an unintended consequence of the 203 language.

Question: I'm trying to clarify this issue because of the Chinese attempts to purchase Chevron during the energy act debates. It sounds like it's open. Is there anything in the FERC standards that would allow them to raise a concern about that?

Speaker 2: The new provision has broad public interest standards. FERC can look at foreign acquisitions any way it wants to.

There's one possibly bizarre exception in section 203A4. The original statutory phrase from 1935 is "consistent with the public interest." The new language says, "will not result in cross subsidies or encumbrance of utility assets." Most would say that's redundant because those things aren't consistent with the public interest. However, some smart lobbyist snuck in the possibility that a cross-subsidy, pledge, or encumbrance could be consistent with the public interest. I don't agree, but one could actually say that the standard for consumer protection is now less than it was before.

Question: Why would somebody say that language is more inclusive?

Speaker 2: The quote is "unless the commission determines that cross subsidy pledge or encumbrance will be consistent with public interest." Until these new standards were in place it never would have occurred to most people that cross subsidies et al could be consistent with the public interest. Now, FERC has to consider that possibility. In the old days I would have argued that any cross subsidies are always necessarily inconsistent with the public interest.

Speaker: US utilities have become a little gun-shy from their experience in buying foreign

utilities in South America and the UK. Generally, companies have promised back to basics kind of strategies to Wall Street. Going ashore is not a big issue at this moment.

Speaker 3.

Today I'll discuss issues from a state commission perspective. The job of a commission is to insure an adequate supply of reasonably priced energy to the people of their state, consistent with broader societal interests and environmental concerns. When we discuss the citizens of a state, this includes companies, and their shareholders. Financially strong utilities are an important part of the formula.

I've always been fairly agnostic about PUHCA. It wasn't being strongly enforced until late in the game with the AEP CSW merger. It had not been particularly onerous. Ultimately, I would vote for the second 'B' scenario described in the conference agenda.

Demands on capital are significant in the current environment. The recent natural disasters, the need for new base load generation, volatile and costly commodity costs, uncertainties in federal environmental policy, and high capital costs all show the need for capital. I'm not sure where M&As show up. It's uncertain whether PUHCA would have kept capital from going towards transaction versus operational uses. The companies in the southeast are among the strongest utilities in the country. They are more likely to take advantage of available opportunities in a post PUHCA world. However, they've got their hands full; their capital considerations are preoccupied. Of course there are some activities; certainly Duke and Cinergy are contemplating a merger. However, the overall interest in M&A in the current environment is not primary.

There was extensive uncertainty for the industry structure for some time. Congress has spoken with respect to the bill and FERC has spoken. Some of the uncertainty concerning RTO's has been lessened.

When the Duke-Cinergy merger was originally announced, FERC immediately suggested that they might have to go into an RTO. This threw a damper over the consideration of the deal. That's changed. Cinergy is in MISO, Duke is not. Duke's looking at a third party administrator and it's working itself out the way it should. There is some certainty now, and perhaps that will help. Ultimately, deals were not being killed by PUHCA. Uncertainty, the EPACT 05, reliability, capital costs, market power and monitoring are all much more important for industry development.

The new enforcement authority that FERC has, the order 888 review, and continuing concerns about RTO costs are all key issues FERC is facing. These are key factors facing the future industry and its operation. Wall Street won't throw a lot of capital at an uncertain regulatory environment. Many on Wall Street are chastened because they threw money at a business model dependent on the continuing development of regulatory policies. This is what's going to affect investment.

The states are assessing their existing merger review procedures. They should do that. NARUC is trying to provide some leadership in that. It panicked EEI that they were going through that process although it shouldn't have. There are a couple of mergers that were announced in the pre-PUHCA repeal world. The way these are handled by federal and state regulators, and the companies themselves will really set the tone. It will show the industry and the financial community what the post PUHCA world will be like. It's a burden for those overseeing these early mergers. It's important that they do it right.

There are three issues for states. First, the issues that PUHCA was intended to address remain important today. This includes cross subsidization, affiliate abuse, the milking problem, etc. In the discussion of repealing PUHCA no one made the argument that standards weren't necessary at all. Except the CATO Institute argued there should be nothing, but that's not surprising. Everyone still agrees

it's important to protect these important legitimate societal concerns. Investors don't need to be protected.

Second, FERC has a new and different role. States have the role they've always had, and some states may beef it up. Once PUHCA is repealed, don't get pissed off when states start exercising their authority. They will seriously pursue the protection of societal interests. We need to acknowledge that the concerns were legitimate, even if PUHCA wasn't the right law. There's no need to chafe at state or federal regulators, or antitrust officials. Companies often get focused on getting the deal done and sometimes get frustrated when folks are doing their jobs.

Third, the real interesting issue will be the non-utility players. When we start seeing a Chevron or a pure financial player come in, I don't know how states are going to react. Clearly, there's greater comfort with experienced electricity companies making acquisitions than someone without that level of commitment. A commitment to operations and to the public service obligation will certainly be important, but it goes beyond that. If you are going to purchase and benefit from the ownership of a publicly granted monopoly, there is an associated public service obligation. It will be a high hurdle for pure financial players, or non-utility players to bring the kind of approach that you see in the experienced utility operator. Consider Mississippi Power's response to Katrina. That's the kind of service you want in return for the monopoly. The operational focus will be very, very important.

Two other points. States are concerned about these changes for good reason. They've been through the TelCom deregulation. As companies remove themselves from being locally regulated companies operating in a monopoly environment, the quality of the service, the corporate commitment to the community, and the quality of the entire relationship are all affected. Even the companies that formerly were run by utility people are run by marketers now, and it's different. States do understand the

economic efficiencies are available. They appreciate that these deals are done so people can make money, and hopefully be more efficient.

Some time ago Duke Energy's prior management got so distracted by other parts of their business that they lost sight of their regulatory bargain. Wall Street tends to tout the cast being thrown off by a regulated utility. They get excited about M&As and other investment banking opportunities that are premised off the regulated utility "cash cow." That's what they like about utilities right now, and that's what they think is going to get us through this difficult time. States want companies to treat their most valuable asset as a valuable asset.

The Kansas Commission and the WestStar deal is another example of a problem relationship. We are cautious for a good reason. Certainly, we should not get in the way of, or second guess, a lot of the business judgments, but we do have an obligation to protect. The concerns that led to PUHCA are important whether PUHCA is in place or not.

Question: Market power ought to be assessed at the federal and state level. Alternately, once could argue that it should be dealt with at FERC. If states do it, it's a duplication with potentially inconsistent results. How do we approach issues with state implications but are federal issues? They're being dealt with differently in different states.

Speaker 3: This is more important to states that have unbundled and are dependent on the wholesale market for their generation supply. It's not a big issue in the southeast. It's clearly important at the FERC level. Some of the original thinking about PUHCA was that it would help prevent excessive market power. Yet more recently others have argued it forced local concentration of an integrated utility, and so it enhanced market power. Generally, it's the FERC's role more than ours.

However, if New Jersey is not happy for not having a hearing on the Exelon deal, it's because they feel vulnerable to market power. They wish the FERC would have more aggressively addressed it so they could be more comfortable. They'll try to do it on their own, because if you are dependent on the wholesale market you need to be concerned about that. As a matter of resources and expertise I think the FERC is the better venue.

Moderator: The classic Ohio Power case where the SEC defended the right of AEP to pay its affiliate above market prices for coal, and took FERC's authority away, demonstrated how PUHCA could reinforce market power.

Speaker 3: That's why the necessity for an RTO in the Duke-Cinergy merger was bizarre. Duke is serving its own, is bundled in its own territory. Cinergy is in MISO.

Speaker: There is no absence of capital to the industry and access to capital is simply going to improve. PUHCA was not a restriction for capital. We've already seen 150 billion plus dollars invested in generation, a lot of money, Billions of dollars could go into new transmission investment, and the same for new base load generation. Wall Street recognizes a need for significant new nuclear and coal capacity. The bigger problems are in rules, regulations, public and societal opinions about things like coal and nuclear that restrict capital. Money is a red herring that some people focus on. M&A just switches capital. Further, M&A has not been a big issue lately. It has ceased; Enron happened. Utilities have environmental expenditures and new base load equipment occupying their time. They are occupied with ways to invest in their core business.

Speaker 4.

I want to focus on four points today. Repeal of PUHCA made a lot of sense. It opens a door to new utility investment by removing barriers to integration and diversification limits. Second, given Katrina, one would think there would be a

flood of investment into utilities. However, it won't happen immediately because of the reasons that people here have discussed. M&A activity is driven by fundamentals; the ability to convince PUHCA and state regulators that your deal makes sense. Third, the recent deals that have not worked show that the industry could do a better job addressing state regulator concerns. The concerns are legitimate: they address excessive leverage, do deals, show economies and efficiencies. Is there still local management; is there exposure to unsound diversification? Four, industry should be proactive in addressing the concerns of the regulators over potential holding company abuses. If they are not proactive, then state regulations may be adopted that make sound transactions and mergers more difficult to do. This could eliminate the benefits of PUHCA repeal.

Let me paraphrase an interesting quote. It's a letter from Ralph Nader to Warren Buffet. He says that although Buffet thinks he will do well with PUHCA repeal, and invest more money in the utility sector, it will more likely end up with human nature prevailing and another corporate crime wave. A big concern is whether regulators can really trust these financial investors. Nevertheless, PUHCA repeal makes sense. The industry has changed and requires a different regulatory approach today, even if many of the concerns that underlie PUHCA are still with us.

One estimate estimated that \$100 billion of equity capital was restricted under PUHCA. That's testimony the CEO of MidAmerican gave in Congress. Berkshire Hathaway has strongly stated that they're ready to invest quite a bit of money in the industry.

Before PUHCA was implemented, utility M&As were astounding, often more than 200 mergers. After PUHCA, there was disaggregation and then slowly over ensuing years there was consolidation. We now have around 3,500 systems, maybe 200 big ones. It's still a very fragmented industry. One would expect consolidation with so much available capital and so many utilities. It won't happen. One of the main reasons is state regulation and oversight.

State regulators are taking actions and thinking about the adoption of new policies. FERC already has cross subsidization and utility asset encumbrance rules that it's getting ready to adopt.

New Jersey has an upcoming rule proposal that puts a 25% limit on holding company diversification. I had a hard time finding the legal basis for their jurisdiction over holding companies, but they seem to think they have it. NERC also has been investigating this area. Regulators need to be cautious. They need appropriate ways to deal with potential holding company abuses without foreclosing the ability of holding companies to bring positive benefits for consumers.

Holding companies can structurally separate utilities from non-utility risks, and they're a good way to further consolidation in the industry. It's easier to acquire a whole company than to merge assets together, and you can still benefit from economies and efficiencies. To further protect utilities, many have been looking at ring-fencing. FERC and the states have increased authority to access holding company books and records under the energy policy act. They don't have much authority over holding companies themselves. They have to focus their efforts on the utilities mostly. To be clear, ring-fencing involves legal measures to insulate regulated utilities from riskier activities by unregulated affiliates through a combination of prohibitions and limitations.

Here are some of the things a commission might run into. One recent deal, KKR-UniSource, was of concern because ring fencing was implemented but it just wasn't enough to offset other risks. Increased leverage from indebtedness is a concern. Even if they remove leverage from the utility and put it at the holding company level, it can be a problem. If it's speculative grade debt at the holding company level, the state may be concerned about incentives for the holding company to cut costs at the utility and not invest for the long term. Policing that behavior on an ongoing basis is a problem. Another problem is if a general financial partner doesn't have utility expertise. If

the structure of the investment doesn't allow for adequate oversight that's a problem.

Commissions will impose a net benefit test or a public interest standard that looks for enough benefits to outweigh perceived risk. It's not just a no net harms standard, the benefits have to be tangible and substantial. Trust matters. If a commission doesn't trust the acquirer then those risks seem a lot larger. An acquirer should come before a state commission and consciously increase trust. This can be done through the deal structure, via commitment to community institutions, or what not.

If companies refuse to divulge information to the state commission, or refuse an independent audit to set a baseline for service quality this is a problem. State commissions want to avoid surprises from non-utility diversification gone bad. Allowing state commission staffs access to real time service level information or holding company data on other investments that have an indirect effect on utility structure.

Let's consider Texas Pacific group's proposed acquisition of Portland General. They wanted to buy the company from Enron and be the white knight but it didn't work out. Overall, a net benefits standard was applied. There was concern again that undue leverage at the holding company level creating an incentive to reduce investment at the utility and risk reliability. Extensive ring fencing was not enough. The Oregon commission argued that even though ring fencing would protect the utility from holding company bankruptcy, it still didn't align the incentives of the owners with the concerns of the state. There were too many potential harms from the short term ownership perspective of this particular financial acquirer. Trust again. The state commission didn't trust that they would make investment decisions with a long term horizon.

Financial acquirers are challenged to show an adequate net benefit to state commissions. In this case, a \$43 million rate credit was offered but it was too speculative for the commission. The company still needs to connect it to an

analysis of actions at the utility that will produce the \$43 million savings. Other benefits were simply seen as actions a reasonable utility operator should already be doing for service quality or local presence in the community.

PUHCA was in place for both the KKR and Texas Pacific Group transactions. Repeal doesn't really matter because the state commissions are already demonstrating a robust ability to protect utilities and customers. This will continue going forward. Second, financial acquirers are at a disadvantage because they're simply not trusted. KKR is a New York City leverage buyout firm. Many people distrust New York City financial types. Texas Pacific Group, a Texas based leverage buyout firm is little improvement, especially after Enron. In Oregon, they already had experience with one group of Texans. They didn't have utility management expertise, were perceived as being short term investors, were unwilling to reveal financial projections, and seen as contributing to financial instability and lacking synergy savings.

A buy-out firm should present a structure that's not overly leveraged. Contrast TPG and KKR with Oracle of Omaha. A financial investor no doubt but they approach the situation through Mid-American Energy Holdings Company. They are Iowa based, solid middle-American utility management with an experienced track record. They can present their Iowa record, their wind plants, and other good works. The emphasis is on the track record, good ring fencing measures, and other structural ways to satisfy regulator's concerns and obtain some transparency.

While the integration standard doesn't apply anymore, the central aspects of PUHCA are still legitimate concerns. States are applying a merger review standard similar to PUHCA. Sound corporate and capital structures are required. Be proactive. Find ways to cultivate a cooperative environment with the state regulators and the benefits of industry consolidation that PUHCA repeal promises can occur.

Speaker 3: The trust issue is important. It's not the good person bad person question, but rather what you do and what you say you're going to do. Does a company's investor profile allow them to fulfill the obligations they make early on? Do the non-utility or even utility investors understand the front end commitments?

Trust also has a practical aspect. While states have merger review authority and other oversight powers, they don't have staff to do much more than oversee a regulatory bargain with their regulated utilities that is premised upon trust. With the exception of the Florida, California, and New York Commissions, they have minimal resources. The SEC has more resources than any state commission. At the state level, the system is dependent upon folks who fulfill that regulatory relationship. If regulators can't trust the integrity of those they regulate in terms of filings and disclosures they are uncomfortable. They are spooked by pure financial investors because they're concerned that they don't understand that bargain. Afterwards, there's not a damn thing you can do and the money's gone. The regulator is left picking up the pieces and triaging the situation. We shouldn't discourage the pure financial players however. If there are good deals that drive value for customers then they are worth getting done. Mid-American is a great example. Buffett has strong relationships with regulators. Regulators need to encourage non-traditional folks to get involved because opportunities are available.

Question: The speakers seem to feel that PUHCA repeal is a non-event. There won't be a massive consolidation of companies from coast to coast and the creation of big regional competitors. The same considerations are there and simply being assessed by other groups or other agencies. Is this really the case?

Speaker 2: No one said there will be a massive consolidation. It's probably the wrong way to think about the issue. The important issue is there's now new types of transactions, corporate structures, and investors. There's new potential for misalignment between the utility obligation

and investment opportunity. These potentials for misalignment are now more numerous so the regulatory response has to be properly calibrated to the problems.

It's speculative to say whether it will be a lot or a little. More important is the right response so that it's measured and we get good results. Better management can replace bad management. Avenues of capital can be accompanied by more expertise. Those are potential positives. There's also the potential for vexing in one corporate family, distractions in the same corporate family as public service obligations. Those are new problems. How do you align a regulatory approach with the new potential for corporate distractions?

Access to capital for utility infrastructure is available as long as regulators set rates that allow for reasonable return on prudently incurred capital. I've never heard anybody disagree with that proposition. There are disagreements about whether regulators made bad judgments about nuclear error, and the qf error. The same for whether investors make good judgments about the magnitude and types of investments. Capital was coming to the industry before PUHCA repeal. Capital might flow from different sources now but the sufficiency of capital is only a problem when regulators disallow prudent costs. There's not much evidence of that.

Comment: I have been involved in transactions that did not go forward because of PUHCA. It was a barrier to significant transactions. You don't hear about them; they're never announced because PUHCA closed the door on them.

Speaker 2: Right, that's inconvenient to the parties to the transactions. However it doesn't reflect a deficit flow of capital to the infrastructural needs of the industry. It's a different point.

Speaker 3: An important concern for PUHCA repeal is the significant new authority residing at FERC. How that is exercised could be very significant. The current Congress was new, and

comfortable with current FERC leadership. They could get PUHCA repealed and still address consumer concerns. It's an unknown in the future though. There is an opportunity for an activist FERC to cause problems (depending on your perspective). There is new authority, and how that might be used is important.

Question: Some argue that the recent energy bill and PUHCA repeal will allow FERC to preempt state reviews. This could happen for states that don't care about competition and FERC does, or for other reasons. Is a federal/state conflict on who reviews a possibility?

Speaker: As a legal matter there's no preemptive intent in Section 203 or the repeal so I don't see a preemptive possibility. A small exception is FERC authority to approve allocations of service company costs. It's a bizarre section and I'm not sure how it relates to state oversight of allocation of service company costs. It's not at the big transaction level, it's on the interaffiliate transaction level.

I would caution against the illusion that FERC somehow has large authority in this area. It's a Washington bias to think that federal level actions are big and state level actions are small. The state role in utility regulation is broader and more comprehensive. The statute for the federal power act is episodic in a sense. It's wholesale transactions, transmission transactions, certain mergers and acquisitions under Section 203, limited financings under Section 204, that's all. FERC is in the news because transmission is central to the industry. However FERC powers under Section 203 will focus mostly on wholesale markets. Technically it should be focusing on retail rate fares also. Section 203 doesn't limit FERC's authority to wholesale but their 1996 merger policy statement and political body language show they won't expand into state turf here. Transactions must be approved in both jurisdictions. Conflict will arise because somebody gets approval in jurisdiction A and not in jurisdiction B, get ticked off and try to create political momentum. Companies go to easier states first and then go to the harder states. As a legal matter it's not a problem but it shows

the need for a common way of analyzing the issue so predictability grows.

Speaker 3: There is an extension of authority to the FERC. If there are new responsibilities at the federal regulator and they are activist this could be tricky. For instance, if Duke's energy merger was dependent on their participation in an RTO it would change state consideration of the economic efficiencies and net benefits. The state regulator has their core retail business to consider, and someone's got generation acquisition approval or merger review approval. They could be at odds on other policy issues and it becomes kind of a tug of war. That's the conflict that I would be concerned about.

Question: Let's consider the seams problem discussed earlier today. PUHCA was national and now the states will do different things. Can you have a policy seams problem where State A wants to do it one way and State B wants to do it another way? If they're incompatible, pretty soon you have people lobbying in Washington for son of PUHCA in order to have common rules across the country. Is there a way to avoid this?

Speaker 2: The industry should try to adopt best practices to minimize the conflict from inconsistent state regulation. The earlier discussion about foreign acquisitions is interesting here. For instance, they could be precluded in Wisconsin because there's a limit on holding company diversification. Foreign utility interests are considered to be diversified. A foreign utility holding company couldn't make an acquisition in Wisconsin because its business is diversified even though it's core utility business. You can have a situation where investment is precluded from some areas.

Speaker 3: There are four types of problems that can arise. One is conflicting standards, and I want to define that carefully. This is when it's impossible for a transaction to comply simultaneously with two different states. Second is different standards with something like reliability. Some state says you need an 18% reserve margin, another state says 15%. That's

not a conflict, you can satisfy both. Third is inconvenient differences. You've got to keep books in Arabic in one state and Chinese in another. These reporting requirements raise transaction costs to a politically significant level. Fourth is procedural differences in regulatory processes. It can be a lifetime for investor interest to finance a particular transaction if there is unpredictable regulatory processes. Lack of clear standards, interest group intervention with rationales other than the public interest:- these cause too much trouble. Most of them are fixable.

An example of conflicting standards is one state requires a debt level of at least 80% and the other state says you may not have a debt level of greater than 70%. These are generally unlikely scenarios. It's more the differences in standards and procedural hassles associated with unpredictability.

Comment: What about rules about the allocation of the benefits that are created by the merger?

Speaker 3: That's a good point. States use different allocation formulae, so you could dry up the benefits.

Question: It would make sense to have everyone in all the states sit down at one time. Then each state could understand the deal; the efficiencies and the synergistic cost savings. Each state would have a reasonable expectation for rate payers in their state. Many companies would much prefer not to do that. They want to go to each state. The deals they've cut in some states have a most favored state clause so they get to true up to whatever another state cuts, their deal remains consistent. I suspect it means the benefits are greater than they've been revealed to be. I don't know how that works, but companies want to deal with each state separately. Maybe to address local politics.

However, it seems more sensible for states to assess these deals collectively. They may end up with different or inconvenient standards but perhaps less so. Companies should be worried about too many pounds of flesh being taken each

step along the way. All of a sudden the deal looks different to Wall Street.

Speaker 3: There's a dirty secret about rate making that applies even without multi state jurisdictional merger, and it's an irritant in every transaction. In strictly enforced cost based rate making, "no regulatory layout" means rates should never exceed costs. This means that any cost reduction that flows from a merger is passed through to the rate payers. That's strict cost of service rate making. If that's true and proper rate making always follows a merger, it becomes anti merger rate making. An acquirer pays a premium that is immediately passed through. The only reason to do it is market dominance, which is real speculative, or being able to withhold some savings by keeping rates above costs through a regulatory rate freeze. A rate freeze only lasts for the term of years of the commission.

This is difficult if one wanted to encourage mergers because they create synergies. From the regulatory side you change the assumption that all savings go back to the rate payers. You settle for a partial cup. It's a merger policy question that no state has resolved explicitly by rule. An investor wants to know how much they will pay as a premium. Departing shareholders want to know how much they can demand. No one knows how much above cost rates will be sustained for how long. This big merger question has to be solved, pre or post PUHCA.

Comment: Furthermore, I'm not sure how you look at that in five different jurisdictions. It's a discussion to have with everybody at one time.

Question: In Scott's presentation earlier, he mentioned the process or the procedures by which states try to address the issues underlying PUHCA or the concerns, the consumer protection concerns, underlying PUHCA, and my question is you mentioned

Three alternatives were discussed earlier for states to address PUHCA concerns: rule making, case by case, or do nothing until you have to. States have few staff resources to do any of

those things except sit and do nothing. Only a handful of states have resources to pursue a rule making or to do the analytical work for a case. Can NARUC play a major role?

Speaker 3: There's multiple answers to that. The first step is statutory analysis. A number of states don't even have jurisdiction over holding companies, so statutory analysis has to go first. The most efficient approach is rule making. If it were done by several states in a region at the same time, there could be some economies of scale. States don't want to be known as the set of states from 2005 to 2010 that blew it. So rule making, statutory analysis and a common effort among states in a region are important.

Response: I expect NARUC will be a forum for best practices to make up for lack of resources. Conditions placed in the merger orders are effective. They're always vulnerable to interpretation by a commission. Companies may make a lot of promises and then disagreements occur two or three years down the road. This is subject to legal interpretation, so there's less certainty statutory analysis and rule making. Some commissions use conditions a lot with success. This is often because the companies are committed, local, fully integrated. There's some comfort level between regulators and companies. A constructive relationship is fundamental.

Question: I was wondering about the structure of the industry. Mergers have been occurring, at a moderate pace. Are we leaving money on the table that the consumer should be getting? Alternately, from Wall Street's perspective, do we not need a more efficient merger policy to encourage a consolidation that really hasn't taken place.

Speaker 1: There's plenty of efficiencies from consolidation so far. There would be efficiencies from national standards, but that's unrealistic. There's 50 states and 500 people up on the hill that can't agree on anything. How are you going to 15 states to agree on a standard? There's too many local issues involved.

Speaker 3: Why should states have a merger policy when the industry is willing to merge under the present unattractive terms. Mergers are approved where you get 50% of synergies in three years and it takes two years to ramp up to the synergy levels you need. Why a merger policy that will attract and encourage mergers when the industry will do that on the terms that exist now? There's little leadership, and few prospects of that changing.

There's been very little academic, empirical work on what the mergers have produced. We should learn more about what a merger produces and how to measure it before we talk about policy. Policy should distinguish between good and bad mergers.

There's a little on economies of scale. The question of economies of scale in generation, at retail marketing, in transmission. Some things, like outsourcing or consolidating call centers, may not work very well in this business. This is partially because electric service is seen as an essential function. Synergistic efficiencies are there but healthy skepticism is important. Often it's a question of improving service.

Question: Can we consider a merger premium a legitimate cost to service? A merger premium is part of the cost it takes to achieve the overall cost saving. One savings example is in corporate A&G. Other things like computer systems, call centers, and customer information systems have huge economies of scale and minimum fixed costs. Often the natural growth rate won't get you there very fast. If the customers pay some of the premium they can get greater overall savings from a merger that they wouldn't get otherwise. Obviously you need to question how real the savings are, but there are cases where they are real.

Speaker 4: That's 100% the point. The legitimate acquisition premium is paid to produce the savings. If the regulator wipes out the savings, then there's no incentive to make a merger happen. If the regulator wants to see some savings, they'll have to part from the normal practice of flowing through all costs.

Unfortunately, the synergy dollars are often not real. Incorrect forecasts are often made about the cost structure of a company over ten years, with or without the merger, that are simply speculative. A premium should be allowable in rate base if it is matched by measurable savings. Shareholders should keep some of the savings, otherwise there's no incentive to do the merge to begin with.

Moderator: One speaker proposed a utility prophylactic approach for ring fencing. A company presents a package and says this is the policy we're going to follow. Hopefully that will reassure regulators and make negotiation easier. Could we apply that approach more broadly to other issues? The telephone experience and loss of local control was a dreadful experience for state regulators. Quality of service and the power of local managers were reduced significantly. Actually showing the savings is also problematic. The Toledo Edison and Cleveland Electric merger had losses that dragged both companies down rather than the savings they claimed. Couldn't a preemptive approach to local control, like ring fencing, combined with a "show me the money" analysis work together to address those concerns ahead of time?

Speaker: That's a good point. One thought is to create structures that give incentives to management to behave properly. Another structure where the managing member gets incentive payments under certain conditions, and the other participating members get a more fixed payout. One could create tax incentives, and develop a structure to encourage management to follow best practices for ring fencing, maintain investment grade credit at the utilities, invest appropriately, and keep service quality up. Incentive based performance based regulation.

Speaker: I'm hesitant to micromanage a company after a merger. For companies, the way they integrate a merger, manage their way through it, is very important. The situation changes. The prophylactic approach for financial ring fencing issues is a good idea. On other

things we should get out of the way and let them manage it. Incentives can work because money can shape behavior, but I wouldn't want to get too involved in their business.

Speaker: There are two important distinctions here. One, this involves incentives that are

created within the company. You want the incentives with the workers, so you're lining up real practice with the corporate rhetoric. Second, this proposal puts the burden of good regulatory relations on the company. It creates a corporate incentive to have good relations with a reasonable regulator. There's nothing like repeal to focus people on one common course, which is let's not make a mess of this.

Speaker: I love incentive based rates. It's, usually a bonus situation for companies. They can earn a superior return and differentiate themselves from their peers if they're successful. However, quantified rate reductions and rate freezes which persist for some time assure the financial benefits in a merger. These basic incentives can also help their managers get the recovery of their premiums and gain good returns on their acquisitions. However, the idea of incenting for maintaining credit ratings is a good idea. It would have prevented a lot of problems in the late nineties.

Session Three. Transmission Planning and Siting

Electricity restructuring has changed responsibilities for transmission investment planning. Are the new responsibilities well defined? Who sits at the planning table? Is planning separate from the decision to invest? Who assure that what is planned is built? What is the relationship between such critical actors as the RTO and state siting authorities? What role, under the Energy Policy Act of 2005 will FERC or DOE play in the process? Who is supposed to take the initiative in proposing new lines? Will the initiative and residual obligation to build remain with the transmission owners, or should that responsibility be shifted in some form? Should RTOs be more proactive in regard to expanding the grid?

Should transmission enhancement and expansion respond to market incentives or should planning drive transmission investment and the market? How will alternatives to transmission be considered or excluded? Who should decide these matters where jurisdiction is so fractured? For instance, in California, responsibility for these functions is divided between the ISO, CPUC, and the California Energy Commission. Now, perhaps with possible federal jurisdiction, there is an effort underway to coordinate on these issues in order to bring clarity and functionality to the transmission planning and siting regime. How does the changing allocation of responsibilities compare across the country?

Speaker 1.

The two most critical issues in transmission planning are who decides what gets built and who pays. In the Midwest, the responsibility for making that decision is pretty diffuse and that has resulted in the failure of the decision process. This is related to the second question of who pays. Deciding who the beneficiaries are for a cost allocation mechanism that makes sense and is consistent with the market is fundamental.

MISO hopes to develop a regional plan consistent with good market operation and reliable operation of the grid. It requires board of directors approval. There is a robust stakeholder process that includes an advisory committee to advise the board of directors, a stakeholder planning committee, and an expansion planning group. There's also an organization of MISO states. It has regulatory commissions from all 19 states. They all provide input, but the independent entity formulates the final plan, makes the decision, and moves it up to a board of directors for approval.

The reality to date is somewhat different. The 2005 plan was really a roll up of independent transmission owner plans. They brought the primarily reliability based plans they had been formulating in the past and MISO made a determination by considering all of them in the regional footprint. They couldn't determine the most efficient way to provide the reliability being sought by the transmission owners. It's still a new process.

MISO is a young organization and they're working to get a better level of coordination. This process actually looks like the NERC reliability council structure. The individual utilities formulate their own plans and roll them into the regional reliability council. There's an assessment of whether it provides for a sufficient level of reliability in aggregate. This structure leads to outcomes in some cases don't make sense in terms of providing least cost energy, even if they are efficient otherwise.

The real decision makers are the states, certainly in MISO. While the reliability organization is able to impose some vision on what transmission expansion ought to look like, it's still limited. MISO can go to states on behalf of transmission owners in support of their development plans. A better system would be to work with the states in a coordinated fashion. Especially where large states have transmission needs that cross state boundaries. Joint action is needed. The Organization of MISO states formed a planning and siting group to provide. Unfortunately it's a voluntary organization, no decisional authority. They only lend legitimacy to the process.

The next topic, who pays. MISO's 2005 plan using the reliability plans developed by the individual utilities is straightforward on that level. Either rate payers or the local utility would pay for expansions in their service territory. The 2006 plan includes some reliability and commercially beneficial plans. It's more complicated to decide who pays. The current proposal is to allocate most of the cost locally, 60 to 70%, and then to have a subregional and a super regional element that would be added into the transmission rates.

Determining what gets built is tied to cost allocation. If the majority of project costs are assigned to the local area, there's resistance to any plan that isn't directly tied to serving local load. A plan that benefits the region but assigns most costs to local load, loses support if a commensurate level of benefit isn't directly received. The Wisconsin area doesn't want to pay for a transmission upgrade in Kentucky, even if it improves reliability. There is an ongoing stakeholder effort to evaluate alternatives for cost allocation, particularly for economic rather than reliability or capacity projects. One option is to convert those costs into a usage fee that's assigned based on transmission usage. This would avoid the distinction between a reliability and commercial upgrade. It doesn't necessarily make the decisions any easier though.

Question: Could you clarify for me what you mean by energy based charge? If somebody's

building a transmission project to relieve congestion, is energy based on who uses that facility, or energy throughout the RTO?

Speaker 1: It would be usage based. The cost would be paid by the folks who are using the specific transmission upgrade.

Speaker 2.

Much of my talk will focus on issues in Texas and may not apply so well elsewhere. ERCOT and the Texas Interconnected System has a history that goes back to World War II. It's one of the ten regional councils of NERC. There's a single state interconnection, with one regulator, the Texas PUC. In '97, they became an independent system operator, and in 2001 they began facilitating the competitive retail market in Texas. It's an active organization. There's 38,000 transmission miles all told.

The big emphasis on transmission planning is teamwork. The relationship between the PUC, ERCOT, and the transmission owners was the result of about six years of hard work determining responsibilities. In '97, they realized that transmission facilities for a competitive wholesale market and a competitive retail market weren't in place. They created a transmission adequacy task force. It consisted of anybody who was interested in the problem, not only the transmission participants but the ERCOT and PUC staff. Defining the roles of each organization was essential.

In 1995 wholesale open access was passed and ERCOT was in charge of regional transmission planning coordination. The roles and responsibilities weren't clear initially. Same for the transmission owners. What if a large constraint mitigation project started in one utility's territory and terminated in another's? These were the problems. We needed PUC involvement in the transmission line certification process. It was a dilemma because it was an open-ended process. A company filed for a CCN and there was no firm end to the. The determination of need was also difficult. If you

want to build transmission then there has to be timely and adequate return of investment. After unbundling, how do you have a transmission rate case without a full blown utility rate case.

ERCOT worked on those issues. They developed a transmission tracker allows transmission rates adjustment based on the previous year's net plant transmission investment. The process in '97 and '98 really defined its regional transmission planning obligations, as well as the roles and responsibility of transmission providers. The PUC really listened to stakeholders and ERCOT with a willingness to modify the rules.

A lot of entities can propose transmission lines in the implementation process. Could be ERCOT, ERCOT staff, the PUC, a transmission owner, or any interested market participant. After a need for a project is determined, it goes through the ERCOT planning process. ERCOT really facilitates this if it's a big significant project, especially if it's a significant 345 project or a critical 138 project. Then, the transmission owner responsible begins engineering the project and proposing various routing scenarios under PUC criteria. They file a CCN at the PUC afterwards. There is a timeline. There's a one year timeframe if ERCOT determines a transmission project is needed for the state's grid.

The transmission task force agreed that ERCOT would determine the independent body that determine need for a transmission project. This was critical. The CCN process with the PUC becomes just a routing process without being more political. You avoid the need determination because it's been done earlier. It makes it much easier. So far it's worked pretty well. After the CCN is approved, the transmission owner builds the project. The annual transmission tracker updates the net plant transmission investments in the prior year. This process has worked extremely well for five years.

ERCOT assesses transmission in sub regions. There are three different areas with different

challenges. Each has its own regional transmission planning group. This is helpful because one transmission provider could install a significant transmission line but the constraint might be on an adjacent system. You could build a \$100 million project but an upgrade is still needed on an underlying 138 KV. This allows a collective assessment of issues within the subregions.

The north Texas group has big challenges in the Dallas area, with lots of congestion. There's a lot of generation in northeast Texas trying to get to Dallas. That requires a lot of coordination because there's five different. South Texas has Houston plus the far south Texas valley area. There's tremendous population growth along the Rio Grand River in the Rio Grand Valley. Load growth, and not enough transmission or generation, leads to plenty of constraint mitigation. West Texas is always a challenge. There's always been a transmission constraint associated with west Texas. It's either getting power to west Texas or getting power out of west Texas back to the east. This is now where most of the wind generators locate their facilities. There's not many customers out there in Marathon, Texas where these facilities are, so the challenge is to move wind power out.

Here are some of success factors. The established and transparent planning process encourages transmission investment. The need determination is separate. Third, the PUC authorizes timely cost recovery. This successful process has produced over 4000 circuit miles of new or rebuilt transmission. There's 345, 138, and 69 KV networks of transmission, so there's a lot of autotransformer capability to move power off the 345 grid down onto 138 and 69 KV systems. There are significant environmental constraints in the Dallas area, so not much generation. Over the last 20 years, especially the last five, they've reinforced the transmission system to increase imports. That's over \$2.2 billion of investment so far. Another 4,000 miles of transmission should be built in the next 5 years; about \$2.3 billion of investment.

Translating this process to multi-state jurisdictions has three different issues. First, developing a single planning process can work anywhere. Other regions do something similar. It's a good process when you get all the participants sitting at a table looking at the same issues facilitated by the regional transmission planning staff.

Two, creating a fair and balanced state regulatory process that results in consistent project certification. Our transmission adequacy process is important, especially with the CCN process. What's the timeline to get something approved? You need certainty for the process. Third, stable pricing mechanisms that result in timely recovery of investments. You get certainty if you know you're going to get timely recovery of investment. This is much harder in multiple jurisdictions with FERC involved. Nonetheless, this is an approach that has worked very well in Texas since 1997.

Question: Please clarify the PUC role in ordering transmission.

Speaker 2: The new legislation in Bill 7 has a provision that the PUC could order transmission lines built. One concern was that if people couldn't get timely and adequate recovery of transmission investment, it wouldn't be built. Fortunately, we've never had to deal with that because the process is working properly.

Question: Are the transmission costs to bring wind power from Midland being socialized?

Speaker 2: Yes. And by socialized I remind you that there is a postage stamp transmission system in Texas. All transmission costs get rolled up. There is a consistent transmission cost across all charged to all load serving entities. Correct.

Question: What is your estimate on cost to bring all that new wind power?

Speaker 2: I'm not sure. Currently, there's 600 megawatts that can come out of West Texas. Some wind farms are located closer to larger lines. ERCOT and the West Texas transmission

planning council have got a plan such that if we get above 1000 megawatts or then a 345 KB loop will be needed.

The state RPS is a big part of this. It gets mixed up between the legislature, the PUC and the folks who are proposing those wind projects out there. It will be \$200-500 million to build those transmission lines. They need to make sure the wind farms are there and the PUC is in agreement to move forward. At some point the need determination could be challenged if somebody doesn't want to see the costs socialized.

Question: How is the need question handled between ERCOT and the PUC? Clearly, the PUC still has to make the ultimate certificate of need decision as a legal matter. However, it sounds like once it goes through the transparent planning process at ERCOT the disputes are resolved. I would like to think a transparent planning process versus an opaque one will resolve a lot of issues. Once the engineers have access to all the information, there won't be that much dispute about what needs to be done. Is that right.

Speaker 2: That is a great clarifying point. I may have over-simplified the. The process takes a long time. The regional transmission planning process still takes input from any stake holder. The PUC staff is involved from the beginning. The question of need gets vetted through this process and by the time it gets to the PUC, there's not much for them to do. They've endorsed this transparent planning process that's been put in place. People could still come back later in the process the PUC would have to deal with it. However, participants have gotten comfortable with the thoroughness of the process.

Speaker 3.

I'm going to discuss challenges and lessons in the PJM process from the last six years. Particularly the coordination between the planning process, operations, and the markets. One of the biggest issues is balancing certainty in the planning process with a need for

flexibility. One of their first principles, significantly driven by generation interconnection requirements, was to have certainty in the planning process so that interconnecting parties would have a degree of confidence that the process was fair and consistent. This has made it difficult to adapt the process as the markets have changed.

They wanted a process to integrate the needs for transmission capability and potential solutions, have extensive stake holder involvement, and, broad connections with the states. Markets and operations had to work with the planning process. They must be highly synchronized. This is something we emphasized in later models of the planning process.

Single entity decision making refers to planning the system as if it is just one system, ignoring internal boundaries within the system to find the most effective solution. In the early days generator interconnection was a big concern. There were many projects, mostly in the east; New Jersey and eastern Pennsylvania. Load deliverability issues were generally fairly minor. Adding transformer capability or minor upgrades to existing facilities. The first three interconnection queues had 52,000 megawatts of proposed projects proposed. Approximately two-thirds of investment was related to interconnection requirements. Early on there were so many generation projects in New Jersey that the problem was getting the energy out of New Jersey. Now it's the opposite problem.

Currently the emphasis has shifted to the center and west of their system. It's a mix of large coal projects in the west and a lot of smaller projects; wind and biomass projects. They also have an emphasis on the ability to deliver energy across the system. There are congestion problems associated with west to east deliveries.

Growth and change in the system has lead to fairly significant load deliverability problems. Reliability concerns about the transfer capability into New Jersey and other parts of eastern PJM have arisen. There's significant transmission congestion through western Maryland and West

Virginia that costs roughly \$750 million a year in gross congestion. The heavy transfers result in reactive or voltage control issues that operators have to deal with in addition to the congestion.

Load deliverability is a problem. This is where you model a localized reduction in generation and ask whether the transmission system is robust enough to deliver energy from the remainder of the system. There are violations of that criteria out through their planning horizon. There are also generating units going into retirement that have made deliverability problems worse.

The whole mid-West area has a cluster of large coal projects proposed and the linkage between them and the eastern portions of the region will be vital. They've put about a billion dollars investment into the plan, although two-thirds of that was for generation interconnections. In the last 12 months they've put another billion in almost entirely for reliability problems including operational performance. They currently have some RMR contracts because they can't get the transmission built fast enough.

They've already implemented some changes to extend their planning horizon. They're now extending the baseline analysis out to 15 years from 5. Within that though, they will stagger in. We're not going to look at 115 KB upgrades 15 years out. They are doing more sensitivity analysis that will be binding in the planning process, sensitivities around load forecast error perhaps. We're looking at ways to assess at-risk generation, circulation from other systems, and market efficiency. They use a historic look at congestion to help create a projection of efficiencies that can be derived in the market as well as the addition of transmission. The biggest concerns are uncertainty. 15 years means a tremendous amount of uncertainty. Generation interconnection is mostly in the two to three year timeframe. Other processes like RPM have different timeframes. The problem is to integrate them.

If we return to the certainty versus flexibility problem, which criteria are used and are they binding? Which is informational? There's

discomfort with the unhedgeable congestion process because it was hard coded into the operating agreement. They are stuck with it and trying move away from it. They need a more robust process with less detail in the operating agreement so there's flexibility. If transmission is on the table 12, 15 years in the future, there are concerns from the transmission owners about investment because of uncertainty in the planning horizon.

Question: Cost allocation is a critical issue. How does it work for PJM?

Speaker 3: PJM still has zonal license plate rates. They allocate all upgrades whether reliability, operational, performance or economically driven on a cost causation basis. If it's reliability, the solution could be in one zone but the load that is driving the need for the upgrade could be elsewhere. There, the allocation is based on the cause of the violation that caused the upgrade to be needed. Operational performance is similar. If they have excessive TLRs in a location and they need to upgrade the system, they look at the flows causing the TLRs and allocate it to the zones at the receiving end of that.

Question: Can you explain what you mean by gross congestion?

Speaker 3: There's an LMP system in PJM. When the prices separate, all load on one side of a constraint pays the higher locational price. Load on the other side pays the lower locational price. The difference is gross congestion. It's the entire difference in dollars. A fair percentage of that amount is hedged by customers through transmission rights or bilateral contracts with generation. For example, nuclear generators in the east run at a lower price than the LMP often. They should be able to hedge through bilateral contracts. The concept is a way to represent the true out of pocket costs that load would bear and be willing to pay to have transmission built to eliminate that cost. If I send you a bill for a million dollars of congestion but give you a rebate for \$900,000, the presumption is that you're only willing to pay \$100,000 to eliminate

the constraint. It attempt to estimate true out of pocket cost that one would presumably be willing to pay to eliminate the congestion.

The details of unhedgeable congestion are explained in PJM's operating agreement and in their manuals. There's a lot on their website also.

Question: You described reliability and economic upgrades for the mid-western power moving to New Jersey. At a very high level, that's fundamentally all economics.

Speaker 3: No, I wouldn't say that. The eastern end has basic reliability criteria violation or violations, especially getting into New Jersey.

Question: The criteria: reliability, economic and operational, operate in kind of a blend across the different areas. Fundamentally, calls by the west east flows. Did those problems exist pre-integration?

Speaker 3: Yes, but you just couldn't get it into PJM – end of the story. Now it's part of their internal dispatch and they have to deal with it.

Question: In one area around Maryland and Pennsylvania there's \$2,000,000 of unhedgeable congestion. Why isn't somebody trying to upgrade to capture that money? It just gets dispersed over the load.

Speaker 3: Well, the fundamental problem with expecting individual loads to step up is that money is spread out over a lot of customers. Developers can't get firm contracts to recover their investment, so they won't do it. People are looking for low hanging fruit. Some developers look to replace wave traps and disconnects to get significant transmission rights and make money. PJM's problem is the rules for fixing that are too strict. They're trying to get more flexibility; if you invite me back in about four years I'll tell you how it came out.

Speaker 4.

I'll talk about current problems in the California ISO; primarily congestion and reliability must run requirements. Generation interconnection and retirements are also an issue. I'll also address their new planning process.

From 2003 to 2004, congestion costs into Southern California south of Path 15 increase by 182%; from \$151 to \$426 million. Additional generation in the Southwest and Mexico came into the system without any upgrades to transmission facilities Delivering this generation into Southern California is difficult. By 2004 they put in transmission fixes and reduced congestion by around 60%.

About 50% of the control area generation in California is under some sort of an RMR agreement. They pay \$364 million in fixed costs and \$285 million in operating costs above real-time energy prices in 2004. On the generation interconnection and retirements, there are 97 projects on queue. About 30,000 megawatts of generation and 5,000 in renewables, mostly wind and a little geothermal. There are 14,000 MW of plants that are 50, 60 years old. Obviously this is a primary driver in transmission analysis.

They need to move from the presently reactive process to a more proactive process, especially for retirements. There are \$4.3 billion in transmission upgrades approved, around \$2 billion in service right now, the rest is under construction.

The last three to four years was an interim period without a capacity resource requirement and no effective market design. This hindered transmission planning. They've been working under a reactive planning process since 1998. They relied on the PTL submitting five year power programs to us. Approval came after a decision that the most economic alternative had been selected to solve identified problems. In the past, they simply told the utilities this is your RMR costs. There were no actions to try and reduce those costs. They started to tally the congestion costs and to plan fixes, but only after enough congestion costs warrant the investment. Lastly, there's a problem with a duplicate

approval process. Once a new transmission line is approved by the ISO, the process is done with the PUC to get a certificate of public convenience and necessity. There are cases where the ISO approved a line and the PUC rejected it.

A new process to solve these problems will start in January of '06. The ISO will independently determine a set of projects to be built. They will be fairly obvious projects, mostly to reduce RMR costs and to mitigate congestion. The ISO is working with CPUC and the CEC on future resource portfolio scenarios in long term time frame. There are two regulatory agencies in California, the CPUC and the California Energy Commission, that license generators that are 50 megawatts or higher. The ISO wants to create a single process with all 3 groups. They are trying to identify projects at 5, 10 and 15 year increments. It makes a big difference to figure out what the system will look like 15 years from now and try to build to it.

Transmission alternatives have always been a problem. Currently, they have no way of doing anything with generation location incentives or demand site programs. They're hoping to work with the CPUC on demand side and resource location as priorities, transmission would come afterwards.

The hope is that a streamlined permitting process with full participation by the CPUC and the CEC will reduce duplicative efforts. They are trying to create load forecasts to help the CEC produce different scenarios of load and generation and retirements.

Participating transmission owners will have right of first refusal on projects put out by the California ISO. If they decide not to build it, then the ISO will take it into a competitive solicitation process for the lowest bidder.

Resource adequacy in the market process is being addressed by a process called MRTU to start in February of '07. Production simulation is a key part of this planning. They're hoping the future programs help tackle issues like market power and things that present production

simulation programs do not. The ISO is working on integration of resource planning, transmission planning and market information. Active stake holder involvement is needed to make sure the right infrastructure is in place. Finally, the ISO works extensively with transmission owners; they know their system better than anybody. They are vital part of the picture to get an integrated process that delivers a five year and ten year overview of transmission development.

Question: Was there a description of the cost allocation rule for the projects going forward.

Speaker 4: No. It is quite simple. Any new project 200 kb or higher built in the State is spread to all rate payers throughout state. Projects in existence today are on a ten year plan that started around four years ago. Currently they are at a 40/60 level, next year it will be 50/50 and so on until all 100% of them are in rate base.

Question: You discussed efforts to coordinate between CAISO, the CPUC and CEC. How will that work?

Speaker 4: The three groups have been working together for the last three months to define their roles, and to determine how information will to flow between them. The process will be open to the public next week. The CEC will process scenarios that assess generation, retirements, and load forecasts. The ISO needs load forecasts on a bus level basis. They don't have that but they will soon. The ISO will take that information along with stakeholder input and put together an initial plan. Once those plans are put out together, the CPUC will analyze alternatives and environmental issues to finish up.

Moderator: One of the topics on the agenda was siting issues. What are the issues for ISO's; approvals, multiple states, etc. How do you get these issues resolved?

Speaker 1: In MISO, you need a certification of need in each state. There is an effort to coordinate at the state level with the OMS to gain a transparency of process that the states feel

they can rely on. The difficulty is the criteria for decision making. In a multi-state project, the states may look at a project very differently. Costs and benefits are a problem if they approve something that impacts their rate payers to benefit another location. Differentiating between reliability and economic projects is a big issue. They don't know how it's going to work in MISO. It's not clear you can get a consistent set of guidelines for all states.

Speaker 3: PJM deals with the same issues. Their relationship in their older eastern states is more established with a better working relationship. Big multi-state projects have been rare but they are coming down the road. There's an organization of PJM states attempting to deal with rate recovery, siting, and that sort of thing. That test will come soon.

Our cost allocation is driven by who the ultimate beneficiaries are so that helps alleviate some potential conflict. The real challenge is to establish a level of confidence between the ISO, the states, and the transmission owners so that everybody is comfortable.

Question: Assume an authority like ERCOT is making decisions about investments in transmission, including economic investments, to reduce costs. With ERCOT it's socialized, with PJM and MISO there's cost allocation which makes it more complicated. What happens next when demand side stakeholders and generators arrive and want in. They say, I can solve this problem for you but I can't do it on my own for the same reason that you're making this transmission decision and socializing costs. Select me, the generator in Dallas/Fort Worth, or maybe an environmentally benign demand side program and just socialize into the postage stamp rate.

We're hearing there's no way to deal with that right now but it will be addressed by central planning and the resource adequacy mechanism. This coordinated planning may take awhile to completely develop. This is one of the principal problems we were trying to eliminate in the late 80's with electricity restructuring. People

wanted to end integrated resource planning and associated problems. Doesn't this process recreate it?

Speaker 2: It's been a concern. Consideration of non-wires transmission alternatives is a key issue. Texas was so far behind on building transmission that this won't become a major problem until 2010. I don't have the answer to it, but I agree that we have to deal with it.

Speaker 3: PJM will integrate any kind of solution into the planning process. However, generation and demand response have to come out of other incentive structures and we plan around them. Some argue that PJM should consider regulated generation solutions for its problems in New Jersey because they may be more efficient than regulated transmission solutions. They currently don't do that. The ISO believes in a market solution that creates incentives for solutions to these planning problems.

Demand response doesn't have predictable behaviors for the market. It's not quite the same. They're still struggling with creating the right incentives for solutions beyond transmission.

Speaker 4: In California, generation and DSM have priority. They are always considered before transmission. Demand side doesn't look very promising simply because the quantity of megawatts are normally not there. Getting a 1,000 megawatts in demand response is tough to do to offset a line that can carry that amount. Generation could get a locational incentive that costs less than a transmission line. Whether that percent is 50% or 90% or 30%, I don't know.

Comment: If the ISO is going to make decisions about generation, transmission, or demand side and then collect it through the access charges, it's not a good way to get to that point. If that's what we want to do then we need a good central planner. We're missing the big picture here.

Speaker: One question is how to tell the difference between an economic and reliability upgrade. If a demand side solution can be

implemented in lieu of a transmission upgrade, that's economic. Should the RTOs be making economic upgrades or simply planning and identifying places where economic upgrades might be beneficial and making sure there are market mechanisms to incent demand, generation, or transmission resources. They'd have to see it, figure out how to monetize it in a way that removes the RTO from socializing costs. Only if the hospital lights are going to go out is it a reliability upgrade. Even then, the hospital could stick a generator on the roof. The first question of determining the difference between reliability and economic upgrades is hard. If you can then maybe the RTO should not be involved in economic upgrades.

Speaker: That's a good formulation. There are two parts to the question; one is recognizing that is the question and then second, how you answer it. I'm concerned that little incremental decisions are obscuring this bigger question. It's easy to be distracted by "oh my God, they're retiring these plants in New Jersey and we have to do something now" and we're way behind the power curve. This puts in mechanisms which create a problem that will be very serious later on.

Question: At some level there is always a demand solution. At some price gap a demand solution becomes feasible, that's simple. Is there evidence of a chilling effect on generation plans because of a risk that a transmission project will obviate the need? Second, one speaker described congestion problems that continue to plague their system. Is congestion inherently bad? Is it the result of using RMR instead of LMP?

Speaker 4: Congestion is not inherently bad. CAISO assesses the price of congestion versus the price of a solution to remove the congestion. It's a simple economic analysis. On the first question, I have seen no evidence that new generation is being affected by transmission. No projects have gone off the queue and described that as the reason why.

Speaker: There's anecdotal evidence. Generators cite the impact of uncertainty. 75 or 80% of the projects in queue eventually drop out. They put

in 12 projects planning to build two, they don't know what the transmission costs will be, the economics change. Sometimes they see the planning process and say, oh my God, they're going to undercut my investment. It's just one of many uncertainties.

Speaker 2: I've not seen a specific case like that. Most transmission projects have a long planning horizon. Further, the generators have a seat at the transmission planning process. I've seen more of the opposite, inadequate transmission available to let the generator get full output.

Speaker: I think it is out there. Generators can't find a load that's willing to enter into a long term contract for a new generator. The utilities don't think they have a risk over the time frame. The RTOs do reliability upgrades to make sure that their load can be served for the lowest average cost for the region. The utilities know that's going to happen. There's little incentive for them to sign a long term contract to mitigate their congestion risk. Generators often don't get built where it may be helpful for them to be built, because they can't find a counter party.

Question: I disagree on this IRP stuff. The effort to do integrated resource planning wasn't a problem. Nor is there a slippery slope related to this kind of planning. RTOs have limited authority to force solutions, no matter what their analysis. They have to rely on customer support. They can't force solutions down states' or customers' throats.

My assumption has been that if the regional planning entity does a good job of comprehensively integrating the resource options and concludes that certain kinds of modifications make sense economically or for liability purposes, that that goes most of the way toward assisting states in their assessment to provide certificates of need. MISO is not seeing its plans move forward at the state level anywhere. PJM has a little more experience. A relatively smooth process like Texas is possible: stakeholders get together, draw conclusions, the planning results are trusted. What's the potential

for getting positive responses for siting and the implementation of resource planning proposals.

Speaker: The cost allocation is very important. In MISO, one of the constrained areas is Wisconsin. It requires upgrades in Minnesota to benefit load in Wisconsin. If a cost allocation mechanism mandates that Wisconsin pay the upgrade costs, you can get the Minnesota PUC to sign a certificate of need. It's more difficult if you socialize those costs out to Iowa.

If the process is transparent and people have confidence that it was done well: looked at the alternatives, came up with the best set of solutions. This goes a long way towards getting there.

Speaker: PJM tries to integrate planning across all drivers, all solutions. It's different than integrated resource planning. If PJM decides that the right solution is to build a generator and give them regulated recovery, independent development through the markets will end. Everybody will wait for an RFP with a guaranteed rate of return over 30 years. They're still committed to making the markets work to provide those solutions. The planning process has to show how they all fit together to establish that level of confidence.

Question: I assumed they don't have the authority to go that far. If they don't look at all the alternatives, then state folks could propose alternatives that are less expensive (rate-based or not), which throw out competition inherent in the market based assumptions of your plan.

Speaker: You're right. They encourage states to force some of those kinds of solutions to happen. The states can figure out a way to make it happen. The RTO will integrate that with everything else.

Speaker: State regulators approved Dominion's participation in PJM base almost solely on non-quantifiable benefits. States are willing to pursue a bigger solution beyond the immediate economic interests.

States are willing to address the broader value proposition and the broader confidence proposition available through the RTO process. They need access to information through the RTOs. Regulators will site, will be supportive of the things that the broader RTO needs, if they believe their rate payers are well served by participating in that broader exercise.

States have unilateral solutions. If they lose confidence in the RTO providing the solution they'll go it alone. If a state decides it really wants control of a resource, or control of the choice of the resource, they'll just get it built. They will distort the market. The confidence is vital to countering any erosion of the ability of the organizations to provide these solutions.

Moderator: Will Cal ISO have authority to implement its new plan or just persuasion? If the ISO identifies something, and then the PUC needs to approve it, how will the process change? How does it jibe with the backstop authority that FERC has, the DOE corridor concept, and stuff like that?

Speaker 4: The ISO always had authority to order a participating transmission owner to build a facility. The transmission owner had to go to the CPUC if a need certificate was required. Now there is an integrated single process between the three parties. We're going to take CEC input, do something with it, formulate our plan, go back to the PUC and get their input. Hopefully, the project will be as smooth.

Moderator: When postage stamp rates came in Texas, does that mean that transmission for the utilities came out of retail rate base? Is there a separate transmission component to the bill for all customers? Or is it still part of retail rate base?

Speaker: Each transmission provider establishes their cost of service. It translates into a demand charge for transmission. In the competitive market, there's a bundled wires charge from TXU Electric Delivery Company. The demand charge for wire services is a sum of the total of the transmission cost of service for all

transmission providers. Essentially, it's a wire charge; it's not a usage charge.

Moderator: In the PJM states with license plates, it's a credit against the revenue requirement that the retail customers would otherwise bear. It doesn't work that way in Texas. OK.

Does that influence the siting process itself? Is it easier or more difficult to site new lines? With license plates, companies located in areas where rates will deviate recover from their retail customers at a different rate than the state might.

Speaker: Right. There were lawsuits, people sued the commission for moving from traditional rights to postage stamp rights. It was initially unpopular. Now the concept in Texas is that the grid serves the state of Texas. There are issues. What if a big project is needed to serve Galveston Island? Why should the people in Dallas pay for that? It's the same problems as multi-state regions. However, both new generation and transmission projects seem to be fairly dispersed around the state currently.

So far, transmission costs are a fairly small cost. Texas has avoided the problem up to this point. I expected it to be more of a problem than what it's turned out to be.

Speaker: If a particular transmission owner has to finance and build a line, and the costs are allocated to other zones, PJM will collect those moneys and channel them back to that transmission owner over a period of years. They don't have to recover it through their own zonal wholesale and retail customers. Otherwise, the fundamental mechanics of the process are normal.

Speaker 4: In California a 200 kWh or higher line is treated differently. Existing transmission lines are switching allocation on a ten-year schedule. On year one, 10% of the charges were allocated to the entire ISO grid, and 90% to the utility. It changes by 10% each year until it reaches 100%. Below 200 kWh, it's just the utility. New products over 200 kWh are automatically rolled in into the entire ISO grid.

Speaker: MISO is similar to PJM. A zonal license plate rate structure based on each of the transmission owners. Currently new projects would just be rolled into the rates for the local transmission owner and recovered as part of the firm transmission charge within that zone. Going forward, there will be an attempt to allocate some of those costs more broadly. This is to address projects that have regional benefits rather than just local benefits.

Question: How do we deal with the intersection between competitive market forces and regulation. We could be using a more market based, and less regulatory approach. There were problems with integrated resource planning in the regulated industry. They spent lots of time arguing and little time actually doing anything.

Alternately, a strictly market solution risks situations like congestion on the Eastern Shore. Why doesn't somebody do something in the market paradigm? Is the acceptable answer to do nothing even if it appears to be in the public interest of customers to move forward and solve the problem. The regulated industry simply builds transmission. PJM and Texas have arrived at an accommodation where markets can lurk, but there's a backstop at the regulatory side to deal with situations that the markets aren't addressing.

Maybe the key is recognizing that there is a tension. If the regulatory solution goes too far, a little bit like California, we risk killing the markets. If we leave it all to the market and nothing has happened, we also risk killing the markets. Political leaders won't just allow customers to pay more. We're in an inelegant but maybe pragmatic middle ground. Is this an accurate way to look at it?

Speaker: PJM developed rules for merchant transmission. They had a number of potential revenue streams they thought were really neat, but didn't generate a whole lot of activity. They came up with unhedgeable congestion and all kinds of information to the market, and that didn't generate a whole lot of activity. It's just

been slow going. We have to find a way to get some more activity, and provide a greater degree of certainty for developers.

Speaker: There are four groups that oversee activity in ERCOT. Stakeholders, or market participants, and their varied inputs, and that's all the way from transmission provider to generator to power marketers to co-ops. The ERCOT staff, the PUC, and the legislature. They always bump into each other on issues. But the market really acts in a competitive manner.

For example, when ERCOT became the single control area operator, power flows changed significantly from what they had been in the so-called regulated market. The market participants changed their behavior. ERCOT ran into a lot of congestion in that first year, zonal congestion. They changed the rules to move away from zonal congestion cost being uplifted to the market. The market constantly requires us to adapt.

Speaker: I have an opposing viewpoint. We're actually in an unsustainable hybrid right now. The regulatory backstop can't be the end state for the industry. Congestion management in inbound service sounded simply but we're realizing that you really can't do just that and have a competitive market. We need a real market, which we're not at now. Or we need a regulated utility's utility. A not for profit utility that plans the grid, puts out fees for generation and transmission, sets up contracts and pays them. The structure we have is not what economists call incentive compatible.

Generation isn't built because no one will sign a 30-year contract. They know the regulatory backstop is there, they don't have to take care of themselves. We're going to have super regional utilities, or something more market based.

Speaker 4: I agree. There's no proposal for a merchant transmission line in California because there's no incentive. California wants to fix these problem but right now it's a matter of priorities, time, and money.

Question: These last conversations have a very important theme. I'm trying to make a sharp distinction between IRP planning versus IRP procurement and analysis. Analysis and planning should be as comprehensive as possible. The procurement is a different issue. This was problematic in the past. Examples include the BRPU process, the six cent law in New York (Amendment 23), or California in 1999, which was a transmission project where the generators on the demand side were everywhere, and then FERC said this system is fundamentally flawed, and you've got to go back and fix it.

It's a question whether ISOs have this kind of regulatory authority. They're certainly trying to get it. I agree with this hybrid notion, but there are two subsequent comments. One is these phrases: inelegant and pragmatic. We should assume that the markets will have outcomes we don't expect. Thus, it's important to have a conceptually elegant, but pragmatic, solution to the problem. It should get the incentives right, so that you're not depending on predicting the income.

The other point about how the current system is unsustainable is also true. Too many rules are ad hoc; the fundamentals are not right. I'm trying to find the line in this hybrid thing; a more principled basis related to the arguments about what the problem is rather than simply a pragmatic solution. One question concerns separating regulated investments and transmission not based on reliability or economics, but whether or not it's big. The lumpiness problem means you can't get the FTR values. If that's the case, then you isolate those cases, but allow the others to work in the market.

We can't make ad hoc decisions. I'd rather an integrated procurement process if you're using a broken kind of market. If you fix it and have a principal demarcation, that's ok. But we need clear principles, as opposed to, we'll negotiate something.

Speaker: The problem is less about being in the procurement business than the backstop

business. PJM bumped into this with RPM and the economic planning process. Stakeholders want to know what you will do if it doesn't work. PJM always set a backstop on the end. They tried to say they're not in that business without success. A lot of people argue that the reason nothing has happened in the economic planning process is because of the backstop process.

Speaker 4: Can we come up with a merchant or market friendly way of building transmission? Is there a better way to compensate transmission that's compatible with the market place. Some new reports are looking at impedance pricing. It sounds technical but it's an attempt to put a market structure behind the value of transmission. New technologies like phase shifters can throw the conceptual design of OMB for a loop. This could all affect the market. The technology solutions could support the markets well. We can make the market technologies work.

Question: Let's consider the new federal backstop role in siting, and DOE's ability to identify transmission paths. How will that affect the ability to build new lines in those areas?

Speaker: We'll see. Hopefully, that kind of backstop is not necessary. More importantly, is to have the right relationship there. It has to be a supportive relationship. Only if we get into a problem, then that process may be helpful.

Speaker: Until we see what they're going to do with it, it's hard to say whether we want extensive partnership with the Department of Energy.

Speaker: I've been assuming that the backstop role was an essential element of making sure that markets work. I was disappointed that the PJM window openings didn't result in projects coming forward, and another major congestion problem wasn't resolved by a market answer. Is it possible that the market will not provide for some of the needs. It's just not possible, and is it possible that the backstop is not interfering with the market but simply a target for blame if

market solutions don't come forward. Maybe the market just won't work for some of that stuff.

Speaker: The backstop is not the reason the process hasn't worked. There are a lot of reasons why that process hasn't worked very well. There's a free rider issue, people don't want to invest because everybody else will get benefit and they didn't pay for it. The metric PJM uses for hedgeable congestion may have been a really bad choice. Obviously it was a political necessity; the process would never have gone forward at all without some form of backstop. Did we get the right one? Maybe not.

Speaker: The backstop isn't the only problem. Given where we are today, eliminating the backstop would be risky. Other problems include price caps that are pretty low; curtailment to load isn't targeted based on people's position in the market; etc.. There are many things that provide disincentives for people to participate as if they're in a commodity market. The backstop is one element of that.

Question: In PJM, when you post the cost of the congestion problem you want to solve, at the same time, you post the cost or the price of the regulated solution. Market participants don't compete to solve the market problem. A regulated solution up front becomes the target rather than the congestion you're trying to solve.

Second, transmission in California has a convoluted idea of "merchant." In other parts of the nation it means being completely self-funded and finding solutions based on market prices. In California it's a third party solution where someone scoops the regulated rate base rate of return from the local utility. We need clearer conversations about what merchant means.

Speaker 3: PJM originally wanted to simply post the market information and let intelligent people find solutions and propose them. We were ordered to post that cost information during compliance appeals. They are not the costs of the actual solutions but rather generic costs.

Question: It undercuts the market signal.

Speaker 3: On the second point, California designed the merchant transmission process around the first model where it is independent. There are revenue streams that derive from the markets that hasn't gone very far. People are suggesting that we go to other model. That discussion may continue for some time.

Question: We're talking about the backstop, the need to get transmission built, and the right incentives? However, I've also heard at least three of the panelists discuss billions of dollars that have been put in the transmission system over the last several years. Are the billions being spent just not enough? What's going on?

Speaker 4: In California they are not enough. Renewables require a lot of money in transmission to bring them in. The cost of congestion is going to be greater.

Speaker 3: I agree. A lot more investment is coming and it's needed. We don't have time to wait. We have to keep developing plans to maintain reliability while developing alternate structures.

Speaker 2: Texas in '98 realized they were behind on transmission infrastructure before implementing markets. Our plans going forward for the next six years have another two or three billion dollars, and that doesn't count investment for more wind coming from west Texas. We're trying to catch up.

Question: My question is do we spend a lot of money on transmission? The answer is yes. There's several billion dollars in the pipeline over the next few years. Is the way we're building transmission helpful? Are markets compatible what we're doing with transmission planning?

Speaker 2: An earlier meeting discussed a hybrid method of bringing transmission onto a system through bi-market participants and market signals. Some of the cost allocation processes

needed to make a system like that work are being done in both PJM and in MISO.

Question: Given the price of natural gas there's plenty of concern about fuel diversity. How does that fit within the planning process? Second, transmission is a mechanism to get different types of generation resources to remote load. There will be more emphasis on economic transmission for, but transmission because of fuel diversity? Comments?

Speaker 4: In California there is no mandate for any particular mix of fuel resources. There is a state mandate that PDO's provide 20 percent of resources from renewable resources. There has to be a dialogue soon about coal and nuclear.

Speaker 3: Fuel diversity in PJM right now is actually pretty good. There's low dependence on oil and natural gas. Most new generation in the east has been natural gas. They'll see results in terms of congestion. The coal is all in the middle to western half of our system. Capacity is not a problem, deliverability is. It will manifest itself in terms of congestion dollars.

Speaker 2: Texas has three or four different new coal projects. TXU just announced two merchant coal plants independent of any regulatory directive. The PUC is taking an active role from a fuel diversity point of view to support the lines. The market is working and driving these issues.

Speaker 1: There's not a lot of gas fired generation in the Midwest. Planning is relatively unaffected. There are two issues. One, if you're trying to evaluate economic upgrades, expected dispatch patterns and expected prices are important. Gas prices play out in that context. Two, if you're evaluating alternatives to transmission lines, and one of the alternatives is gas fired generation. If you're trying to do an evaluation of relative cost it would certainly enter in there as well.