HARVARD ELECTRICITY POLICY GROUP
FIFTY-FOURTH PLENARY SESSION

La Jolla, California
THURSDAY AND FRIDAY, MARCH 12-13, 2009

RAPPORTEUR'S SUMMARY*

Session One.
Formulating and Enforcing Reliability Rules:
Assessing the Relationship Between the ERC's (FERC and NERC)

The theory behind the system for formulating and enforcing electricity reliability rules is not complicated. FERC, as the transmission regulator, has the overall regulatory responsibility, but, in carrying out its responsibility, it should be provided with the highly skilled technical assistance and advice from NERC. Does that theory work well in practice? Two concerns are traditional issues for NERC. Does NERC pay sufficient heed to the balance between economics and reliability, or simply ignore the former and focus exclusively on the latter? Should NERC's views be given deference, given the organization's reliance on its committees and regional councils, the members of which are generally employed by utilities? This may be a factor in the thinking behind those who have described NERC as under-funded and –staffed.

At the same time, others ask whether NERC is driven by FERC or by its members, fearing that the organization is too eager to please its regulator and not demanding more respect for, and deference to, the expertise NERC and its committees possess. There are complaints about lack of clarity in rules, many of which were hastily drafted after the 2003 Northeast Blackout, and the absence of appropriate processes and penalties for dealing with alleged rule violations. Moreover, the process for adjudicating the violations alleged is seriously backlogged. Are the critics right? What is the appropriate relationship between FERC and NERC? Should NERC be more self-reliant and less dependent on its members to carry out its mission? What is the optimal process for handling reliability rule violations?

Speaker 1.

I'm going to cover some history and keep it short and as interesting as possible. Section 215 was the best part of EPAct. For all its growing pains, the glass is half full. That's my starting perspective; we're better off now than before. There are growing pains with tension over how it would work. In addition I'll try to address some of these issues from the perspective of the FERC.

The legislation had been in the works for nine years. Many assumed the one major change would be to make the voluntary regime mandatory, and add penalties. They assumed it would work via a bottoms-up, industry driven process for creating rules, as in the past.

PHONE 617-496-6760 **FAX** 617-495-1635
EMAIL *HEPG@ksg.harvard.edu*
79 John F. Kennedy Street, Box 84
Cambridge, Massachusetts 02138
www.hks.harvard.edu/hepg

Enforcement would be different but handled primarily at the regional level, with NERC in a limited role for consistency, and FERC as an appellate function, again a limited role. It has not worked out that way.

It may evolve to that over time. FERC wanted something different. Some growing pains are natural and others are self-inflicted. It's both but it's always hard to tell whether it was 70% natural and unavoidable, or 70% self-inflicted.

From the FERC's perspective on standards development, there is a lot of expertise within the industry. The industry knows better than FERC how the system operates and what rules can function to increase reliability. For instance, market manipulation is certainly not a core function of any company. Alternately, reliability is a core function of utilities. They take it seriously, it is the heart of the standards development process. FERC sees the standards development process as a voting process. This means that a standard with civil penalties attached to it that's too strong will just get voted down. That's why they've steered away from it.

There is consistent pattern when standards are voted down in reliability. The way section 215 is structured, if a standard is voted down, it just sits, and has to be redrafted. This created suspicion, rightly or wrongly, about the standards development process, and FERC took a very aggressive role.

To be fair to the Commission, it was a less aggressive role than it could have been. Not a single standard was remanded in the first wave. This is significant, it could have been more aggressive. However, when the Commission accepted the bulk of the standards, they ordered a lot of changes. Some of those changes were very specific, and some were unhappy about them. They felt that FERC had too heavy a hand. These growing pains will probably continue for some time.

The record FERC gets is like a floor colloquy. The Standards Development Committee proposes something, comments come in, it gets redrafted, the Committee has to respond to every commenter, then there are more comments. The record FERC gets is often enormous. There is no technical report that's submitted saying this is why a particular decision was made on a technical issue. Over time FERC will probably need to take less of a role and NERC will have a stronger role for the process to work better. It's unstable and unsustainable to have the industry drafting standards. Having FERC taking a highly aggressive role at the other end is also not good. NERC will have to take a stronger role and the FERC will have to recede. The timeframe is 5-10 years, not two years.

There was an expectation of strong regional enforcement with FERC in the background for appeals. It hasn't worked out that way. The FERC knew that the regions, except WEC, did not have experience with enforcement. They wanted vigorous and active enforcement from the beginning. Chairman Kelleher wrote an article in the aftermath of California arguing for better power and more authority over manipulation at FERC. They wanted civil penalty authority, and expected to use it. Their reputation with Congress in 2004-05 was very low. They don't report to the president, they report to the hill. A reputation for strong enforcement could address that to some degree. Further, unlike other areas of FERC regulation, there are eight regions, and a concern for consistency also existed.

I'd argue that FERC made a mistake of talking about consistency on day one and not talking about achieving it over time. Let's consider an example such as a hypothetical first case in an area like network resource designations. A company is under investigation. These kinds of cases are almost always settled. It's risk-assessment, litigation, settlement. If the settlement comes in at $6 million and consistency is paramount then everybody else that has a case anywhere near that has to have a $6 million fine. This was particularly problematic with 8 regions that had been treated differently before. They should have evolved over time, let things come through the system. This has also contributed to the backlog.

To wrap up let's think about the future for enforcement. The current system is unstable and unsustainable. Over time it should evolve towards strong regional enforcement and more authority at the regions with an allowance for differentiation. The context for each of these cases are so different from each other. Only the most simple violations are the same. They shouldn't be spending resources on them anyway, they shouldn't be fining people, and they don't need an infrastructure focused on 70% of the cases that have 10% of the harm. They should use scarce resources on the most important cases and standards.

This leads to one final point. One of the problems with implementation of 215 is simple resource allocation. FERC is spread too thin. They are spending time on every standard. NERC's recent filing on its standards development process showed that the development timelines on many are slipping. There isn't enough people to do all the work. They're focusing on 700 subparts. There needs to be a good prioritization.

Speaker 2.

I'm going to use three different approaches to this problem, and I'll consider NERC's role throughout. The first is to ask what is being accomplished and is it being done well. Second is to examine these issues program by program because there are significant differences. The question of self-reliance versus regulation is different within programs. Finally I'll consider these questions from a management and organizational design point of view.

First, what are we trying to solve? Section 215 and an ERO were set up to create an international regulatory authority with a uniform set of standards across North America. The industry needs the same set of standards on both sides of the border. It accomplished that in Mexico through WECC [Western Electric Coordinating Council]. From this perspective, the same set of standards are in place in the United States, every province of Canada, and in the portions of Mexico that fall under WECC.

Second, it was to get the 1% of folks who weren't complying with requirements to comply. A voluntary approach was not working. Some of these requirements are basic functions like trimming trees and relay maintenance. For instance, on Aug. 14 2003 there were four transmission lines that went out of service because of vegetation contacts in a single hour. In 2008 there were five outages because of vegetation across all of North America in six months. This is a dramatic difference. It's been decreased by a factor of 10 in 6-7 years. It's not the most popular program that the NERC has but it is working. The purpose was to draw a bright line in the sand that was not trust-based or voluntary. This has been challenging but it is important. I certainly wish we'd seen similar oversight in the financial markets and that they had been more aggressive in pointing out what needed to be changed there.

Third, there is an attempt to remedy an inappropriately low defined level of reliability for the bulk power system. It is an attempt to change the status quo and raise the bar. The balance between economics and reliability is not a factor when NERC requires 100% of the industry to do what 99% is already doing. Well, 99% of them already figured out that was the economical thing to do. However, attempting to define how redundant the system is has many more issues. The question of who's footing the bill becomes very important if new standards are being set. The cost of a blackout is dramatic. Thus the FERC is well within its authority to push for higher standards, but everyone needs to know what the distinctions are.

Let's consider things program by program. In the standards area, the FERC put out a whole long list of to-dos in Order 693. It would be very challenging to do this in a voted self-regulatory system. This is the appropriate situation, and shouldn't be surprising for folks. This has gone as people expected.

In compliance it's a different situation. NERC is not self-regulatory when it comes to enforcement. They shouldn't take direction on that. That doesn't mean they cannot learn and take feedback, but compliance is part of their regulatory responsibility.

In assessments they are almost entirely a self-driven organization. Everything they do in assessing the system is built up from the users: owners and operators. NERC endorses that and has resisted the notion that they should do independent assessment or forecasting.

The last thing they do is critical infrastructure protection and cyber security in particular. Here they're trying to create standards where there is nothing in place today. This is entirely different than attempting to write an industry standard where 99% of the stakeholders know what to do. This is a very, very challenging process that has led to the tensions. It's probably one area where they need structural change or it won't be resolved.

Let's move to the third major overview and look at management and organizational design of NERC. Trying to have eight regions implement this program effectively from day one has been a significant challenge for NERC. NERC is not an employer, it is a delegated agreement. Each region is trying to draw the appropriate line between self-reliance and regulatory reaction. This occasionally results in unhealthy and counterproductive actions and motives.

Structurally, it would be much easier for NERC if they had eight field offices and they were implementing the program, even with some flexibilities between regions. Since NERC has no formal authority, there is no mechanism to resolve some of these issues.

To wrap up, reliability has been improved, the law has been a success, and mandatory is necessary. That being said, it is a system in flux with growing pains and lots of things they can do better going forward.

Speaker 3.

The standards are developed by the owners and operators through a very formal process. There are standard drafting teams, there is voting, and every standard much be approved by the NERC board. It then gets filed with FERC and the Canadian Provinces. Many times FERC has comments and that's caused some consternation.

On issue is the interpretation of these few words in Section 215(d)(2): "Due Weight." What does this phrase mean? Supporters of Mandatory Standards believed that was a relatively high hurdle when they were working through the legislation. Others believe that "Due Weight" was much more deferential than FERC is interpreting it now. That may have to be decided by three justices in an appellate court one day – it is a source of tension.

NERC has a wonderful website, everything is there, all the standards under development and formal interpretations. There is a lot of work being done by an awful lot of people in the industry and NERC staff.

The tree contact issues were serious. The loading on the first line that came in contact with a tree in the August blackout was 44.5%. However, the process of getting the standards to Version Zero requires interpretations in the field. Many parties that are audited feel sandbagged because they've made their best effort estimation of compliance. It's not clear in an auditable situation what is needed to comply with the standard. Many thought they knew what was needed to comply with the standard, and when they are audited it turns out to be a completely different process.

What happens when it goes up to FERC? FERC directs changes. There are tensions when the standards drafting team and the ballot body disagrees with the FERC directive. At the last board meeting, there was a lively discussion about a standard that the NERC board approved that did not include one item that FERC directed in Order Number 693. It's clearly still a work in progress. The owners need to get there on their own. There's definitely tension.

There are some critical questions. Are there too many standards in the end? Are some of these good practices and not something that should be incorporated as a standard? For instance, getting rid of the Time Error Correction Standard took forever. Everyone agreed it was not needed anymore since there are digital clocks and GPS, but it still too long a time. Some regulators believe you can't get rid of a standard because it's needed for reliability. However, this was a no-brainer. Another cause of tension is violation severity levels or violation risk factors. They come into place in the penalty phase, but FERC doesn't consider them part of the standards.

There are also problems with vagueness. One of the terms in the 215statute is "Adequate Level of Reliability." NERC had defined adequate level of reliability and there was a spirited discussion about where cost-effectiveness is considered. When new standards are being considered, this has to be addressed. The industry doesn't need a big study to know that N minus two, in all cases, is more reliable than N minus one and N minus three is more reliable than N minus two. Nonetheless everyone knows that the industry cannot generally afford that, except in places such as New York City with its risk, the Mass Transit, and the high-rise towers. There it's obvious that risk outweighs that cost.

There are two issues here. First, this analysis is not quantitative. It's done as a matter of voting. Often when a standard is introduced, there's not even a qualitative analysis demonstrating that it isn't cost-effective. It's simply handled in the voting. Second, there's a question of how clear a standard is.

Here's a controversial example. There's a standard that says a company has to log the time of entry into a critical facility. So do they have to log when somebody leaves? It seems to me the standard is pretty clear, but often it isn't. Further, logging egress may have a substantial cost to it. Does it improve the reliability of the bulk power system such that it is worth the cost? In Washington, these assessments are usually perception and not reality. Any entity perceived as not doing everything to protect reliability is characterized as being "you're either with us or against us."

There's a backlog of violations on the compliance side. As of the end of January, it's 1,800 violations. No one expected that in a year and a half, there'd be 1,800 violations. Many of these are what I would call Mickey Mouse violations. Somebody cannot prove they have the name of the FBI contact to monitor sabotage. NERC is truly between a rock and a hard place in this. It is driven by FERC's view that you need a complete record. If a cop pulls you over for a broken taillight, they run the plates, check for a gun in the car, issue a ticket and that's the end of it. FERC has a different view with much higher enforcement. That has to be addressed. From a staffing point of view, NERC and the regions will have to crank out 200 violations a month to get the backlog down by the end of the year. That is highly unrealistic.

Let's discuss the penalty matrix. FERC has insisted that everything be in penalties per day. There are huge ranges. The "high severe" is \$20,000 to \$1 million a day. In federal sentencing guidelines, that'd be "one day to life in prison." [LAUGHTER] Clearly, the system needs to be improved. The time to process violations to get the record and complete the investigation is simply too long. These delays mean that there is no precedent for companies to look at. Without precedent it's very hard to achieve consistency. Further, the system does depend on plea bargaining and settlements just like the criminal justice system does. The process needs a traffic ticket process for some of the more minimal violations.

CIP, Critical Infrastructure Protection, is enormous. What procedures should there be in a cyber emergency? The stakeholders and NERC have got it pretty well worked out. However, some in the federal government want the ability to take control of the electric power system. The former chairman of FERC said if we get information that there's going to be a terrorist attack in a certain city, the government should start moving the spare transformers there. It's been 35 years since I've been in the Air Force, but it seems to me that's the last place you want the spare transformers to be in the center of the attack. [LAUGHTER]

Most stakeholders agree that we are more reliable. Everybody wants to get the feedback loop into the standards, learn from the compliance audits, investigations, and the other assessments that NERC does. Feed that back into the standards and make the standards more effective. When you measure and when you get the feedback that's when we're going to move toward a higher level of reliability.

Speaker 1: Yeah, you made a point about the standards being ambiguous in Version Zero. In the legislative process ambiguity is sometimes the intention to get the votes.

Speaker 3: It was not intentional. Skills are needed in a standards drafting team. There are engineers who have spent their whole life at NERC that know exactly what a standard means, but it isn't written in a way that is clear for auditable purposes. One of the most controversial is the vegetation management standard. FERC has interpreted it as saying that any violation of the clearance zone is a violation. The standard doesn't say that. Whether it should or shouldn't isn't the question, the issue is that it is a newer interpretation that has caught many unawares.

Question: Can you give an example of the conflict between reliability and competition?

Speaker 3: It hasn't come up at NERC. It's within the same sentence in the statute. I was trying to deal with the interpretation of what "Due Weight" should mean. The closest they've come is the ATC Standards that have been directed in Order 890 for NERC to clear up. ATC starts getting pretty close to competition, but that issue has not been a problem.

Speaker 4.

I recently found a NERC press release from ten years ago saying that they endorsed legislation for mandatory reliability rules. The phrase that jumped out at me was the call for an "industry run self-regulating organization." That's what happened. So what's different in the Energy Policy Act requirement? There are three areas. First, there is publicity about what happens on the grid. There has always been illumination, no pun intended, when there are blackouts. Now there is much more. There are sanctions, which we've heard about. And then there is independent review. With independent review the governance and the funding of NERC is separate. It would be interesting to contrast this model with RTOs.

With publicity previously folks would hear about near misses at the NERC or regional council meetings that never saw the light of day. Now some of that information is coming out. It's having an interesting effect on transmission owners that don't want that kind of publicity. This may be more critical than sanctions, especially as companies get beyond their footprint building transmission.

With sanctions, $1 million a day does get somebody's attention. There's no linkage between the benefit a company may have from violating the rules that links back to the potential violation. The companies weigh the costs and benefits of meeting the rules even if it shouldn't be that way. On independent review, the governance of NERC is different now. The funding decisions are different and there's a FERC budget process. That will manifest itself in things like the audit teams. When a reliability audit team shows up to a utility, there's a new level of seriousness. There's less opportunity to try to work a backroom deal out of it. There's new transparency. Nonetheless, enforcement will need more resources. They need to get smarter in allocating the enforcement resources. Getting the information out is critical – this is the big area for discussion and problem-solving in the future: are NERC and FERC getting the right information? The Transmission Owners and Operators Forum is involved in that. Is it really helping or is that a vestige of the old boy's network that existed before? I'm not sure.

The reliability regulation is so important because it's a key measure of transmission performance. It's a new performance metric. Previously it was whether electricity was supplied at a reasonable rate but now it's also whether it's reliable. There'll be new measures for regulators. This will be fascinating when utilities or transmission owners go beyond their traditional geographic boundaries. Regulators won't know much about the company, no long history. This will be a key issue as other companies look beyond their traditional boundaries to other parts of the country. For example, Southern California Edison having to deal with the Arizona Corporation Commission. AEP and ITC are working things out in Kansas. New transparent reliability measures will help regulators get key metrics to help them determine regulatory approval.

The vegetation management issue was a watershed. It was the first big public test of the new standard process. It forced transmission owners to explain to the public, why are we cutting down your trees, and what is a NERC or a FERC. It helped force a lot of utilities to get back into putting money into O&M budgets. Previously there was a reactive approach. They didn't do anything until something bad happened. Now companies are starting to switch their planning process for budgeting purposes and being more proactive, and that's probably a good thing.

When one considers the next steps, there are two things happening in Washington. There's a question of whether NERC's mission should change. Should they get beyond reliability?

Should they be looking forward to environmental legislation, is there a reliability component? It's a different mission, and one has to consider is this the right institutional framework? Further we don't know if the transmission legislation will be standalone, part of climate change legislation, or part of RPS legislation. There's serious talk about putting in a planning component, inter-connection wide planning for east, west into the legislation. None of the legislative constructs so far answer the question of who's going to do the planning? It's a very important discussion to have.

Some have argued for the planning to be done by an independent entity, that would be sanctioned by FERC, that would have an industry component. This sounds like NERC. Some don't want to have NERC do it; it raises all these questions about the history of NERC and its relationship to government. I'd argue that NERC is the right entity. If a planning requirement for the transmission grid is needed than NERC or a NERC-type organization is probably best suited to do that.

So, what does one do about the RTO planning processes? This is a question without an answer so far. I look forward to the discussion to begin to figure it out.

Question: One of the speakers discussed the challenges of consistency within international compliance and eight semiautonomous regions. This raises questions about the balance of power of NERC and FERC, particularly in that international context. How does one achieve effective compliance across North America with the multiple Canadian Province authorities and multiple structures in Canada? Not all the provinces even have legislation that implement it yet.

Speaker: That's all true. NERC is engaged in discussions with each of the Canadian Provinces. NERC is recognized on all matters, except for mandatory enforcement and penalties. There is a single set of standards. The Provinces participate in information provision. There are some issues there from time-to-time but successful overall.

The enforcement regime is different. Ontario does have penalties today. However, there are real sovereignty issues. New Brunswick is coming forward as well.

Question: Does the lack of a $1 million penalty make a big difference?

Speaker: NERC is attempting to get the same level of enforcement in each location. So far the standards are consistent but the enforcement is not.

Speaker 3: At some point a US Regulatory Authority could change a standard and a Canadian authority might not like it. This hasn't happened but it could. Sovereignty is a real issue and it's not easy. About a quarter of the load and a quarter of the money for NERC are the result of Canada. It's not trivial.

Speaker: It's not a reliability issue, per se, but interesting discussions do take place. The Michigan-Ontario interface with the phase shifting transformers and the Presidential permit also translates over in the Ontario-New York interface. It's a messy diplomatic process. There's no easy roadmap on the enforcement part of the reliability rules. It's a good first step, they've accepted all the rules.

Question: One of the other changes that happened when we went from a voluntary regime of compliance to a mandatory regime was the need for documentation. It really raised the bar on the requirement for documentation to prove that you're in compliance. Half of the 1800 violations are supposed to be documentation-related. Is the focus on documentation too high? Can we focus more on actual reliability than on documentation? How does one address that?

Speaker 2: First, NERC is working on speeding ticket process for less important violations. They would accumulate and account for points, not quite the same as parking tickets. Second, there have been real improvements in the bulk power system as a result of the documentation requirements. Documentation requirements identified relays that were not being maintained or gaps in a black start recovery program. They are creating real improvements in the bulk power system because they help owners and NERC know what they did or didn't do.

Interestingly, when NERC was looking at the proposal on the short form settlement speeding ticket system they realized that few violations actually fall into this category. The notion that everything is merely documentation might be a little bit of a myth at this point.

The speeding ticket violations have to have a complete mitigation plan, have to be a documentation issue, a low or medium VRF, and a low VSL. There are actually few violations that satisfy all those speeding ticket factors.

Speaker: On the NERC website under compliance resources the statistics are listed and they show that on average, under 50% of the violations are document-related. The documentation is important; it channels the work to make sure it's done right.

Speaker: The downside to the documentation is that the owners and operators do not know what documentation is necessarily needed. That is an area of friction. Some regions require the provision of a negative, in other words prove that you've always done A, B, or C. Some of these things are impossible to do. The documentation standards need to be clear, and within the realm of reason.

Speaker: Do we have too many standards? It's necessary for a very important standard. However, we should only spend a minimal amount of societal resources on documentation for something with a low VRF, like the 700 sub-requirement. If FERC found something on an audit like that in any other regulatory area, they wouldn't penalize anybody, they would move on. The most important standards need to be prioritized.

Question: One speaker discussed section 215(d)(2) "not deferring with respect to competition." Let me present a hypothetical. A standard comes in that has an effect on competition and it looks as if NERC's technical expertise has yielded to the common denominator of their members for the standard. My first question is what should we do?

Second, and unrelated, how can one do reliability and ATC (Available Transfer Capability) without having a good picture of loop flow?

Speaker: Let me address the second one. I'd argue that since Order Number 888, ATC has to be calculated using a network analysis. If a proposed transaction is going to overload a neighbor system it should be denied. FERC has since said that one can't turn down a transaction because it overloads someone else's system.

Question: Is that a reliability issue?

Speaker: Absolutely.

Question: Why aren't we dealing with it as a reliability issue?

Speaker: They are. The new ATC standards in several of the methodologies do that.

Speaker: I'd like to discuss the deference issue. Generally appeals courts give FERC deference when it either agrees with FERC or it's bored by the case. [LAUGHTER] Generally, this seems like an abstract standard that doesn't have any real-world implications. FERC should pick its battles for the standards that are extraordinarily important. On those they should dig in and use all available technical expertise and take a hard look at those. Most everything else they should let go.

There are different goals. One is raising the bar. That's different from enforcing upon all participants something that they're currently doing. That's different than determining what new standards will be that will be enforced in the future. Clarifying these goals helps the discourse, it helps them understand what they're doing better.

There's got to be some set of cost issues. When one goes outside the industry, there's often little consistency. For instance, what's the standard charging device for a cell phone? Setting a standard is where everyone has agreed on something and getting everyone to meet it. Raising the bar is moving to the next level of chargers. It's a different thing. The FERC needs to be clear that they're getting consistency on a standard, developing a new standard, or creating an improved response on a standard.

Speaker: The interpretation issue and the vagueness concerns are important. I've been to one or two technical conferences on enforcement at the FERC. The commissioners are wonderful people and good public servants but they're not as much in the detail as the rest of us. They would often ask the speakers are any of our regulations vague? [LAUGHTER] Some of the staff would start looking at their toes wondering are there any of their regulations that are clear? [LAUGHTER] There is tons of ambiguity.

Question: There are reliability improvements across the country. There is value. As we continue to evolve this framework, what's the cost benefit and how much compliance work is leading to operational changes? For instance, I don't think a single engineer or operator has been added. There are tweaks and better documentation, and more compliance people.

It's also changed the nature of the relationship between operators and the reliability bodies. Everyone is focused on compliance and transparency, but also now that if NERC or WEC calls up an operator on the phone they have to be careful about what they say. Any operational discussion, especially real-time has concerns about anything they say can be used against them. It's a new mindset. This has costs.

It's hard for companies to figure out unclear regulations, and unclear penalty exposure. Are there ways to engage with participants and provide transparency, including specific questions that could lead to real improvements. So, for example, when there is an issue at FERC today, companies can approach FERC staff in many cases and get consultation, not action letters, on an interpretation issue. A discussion ensues on how things should be interpreted and an interpretation letter may be issued. There is no similar process in NERC and it could be really helpful. Similarity, transparency in penalty calculators would be helpful too. For instance, more specific guidelines that if a company has a violation of Rule 3A.B, here's the specific risk exposure a company faces. This would allow a company to adjust their actions on the fly, and do a better job prioritizing key issues. From a company perspective, there's been a 20% improvement in actual operations but an 80% increase in documents.

Speaker: That's good feedback – I think the process for NERC is transitional. There are confidentiality issues so that interactions have not been made public for other companies to learn from. That's something they may need to reconsider. There have been situations where operators are disclosing themselves ahead of time, even though NERC's rules don't allow for it. Perhaps they should be engaging in more of that or set up waiver mechanisms so that information can be shared.

Speaker: All public companies, if they have an alleged violation, have to evaluate whether they need to make an SEC disclosure. They need to evaluate whether it is material and assess where it would fit in the penalty matrix. NERC could do things without violating confidentiality. For example, the most violated standard in 2008 was the G&T Relay Testing Standard. It's an important standard. There's no confidentiality problem with providing statistics on the raw information. Providing the categories they have found. For instance, in 250 alleged violations, 100 have relays missing from the database. This gives a red flag to companies, start checking your databases to make sure they're there. Or perhaps 20% of violations are missing their testing period by less than a week. Giving out this kind of general statistical information provides useful data for all companies without disclosing any company, any violations, or providing prejudice in any litigation. There needs to be an informational feedback loop in the standards process.

Speaker: The cost benefit point is an important one. I don't expect a whole lot of progress in the near term, but it's something the regulators and industry should focus on over the long term. The bar is being raised, but there's a motherhood and apple pie element of reliability that it's always good, it can never be bad. There are biases that push one far away from cost benefit.

Speaker: Sometimes the standards are big and ambiguous and need clarification. Other times it's a shifting of the responsibility to the transmission owner. In the vegetation management issue. The standards call for no outages from contact. Everyone agreed to a 50 foot clearance but they were never going to get that because of resident complaints. Companies just wanted to clear-cut everything. The companies realized they had to bite the bullet and design a management plan that could be explained to right of way residents and still also address reliability. The industry took responsibility to implement this seemingly vague standard. There's some burden on the industry to figure out the details to a vague constraint.

Question: In part this is a gradualist approach that accounts for the views of various stakeholders. How does this deal with situations where that's not what we need? This may be a slow motion process with a reasonable conversation that may actually make some standards more lenient.

Let's assume that we push for renewables and demand-side and a Smart Grid and everything is adapting well. That world is inconsistent with the first principles of the model that NERC is following. NERC makes a decision about installed capacity of generation and transmission and everything after that is random. They don't address anything else beyond that reliability standard. In the new world I just described one can adjust demand through DSM or scarcity pricing and various smart signals.

If those signals really exist, then we have to determine why the implied value of lost load for NERC standards is $500,000 per megawatt hour but the price cap is $1,000. There's a big lag in that question. It's going to need to be addressed. It gets even more difficult in different jurisdictions. Can one relax the standard and go towards a market-based system for reliability, but not in Ontario. Are the rules different? How does the NERC process confront the problem between markets providing reliability versus standards, and differing approaches in different jurisdictions?

Speaker: Let's address some assumptions. The first is the difference between operating reliability and adequacy. Much of the advancements are on the adequacy side. They have impact on operating reliability. Nonetheless, the process is incremental and it's not well-suited to establishing a standard for something that is brand-new. Standards related to cyber security are the same challenge. The same with interoperability of devices in Smart Grid. The process may need to be adjusted. The process is self designed and the trustees would have to set up a different system that would have to be approved by the FERC with full input by stakeholders.

Speaker: As a separate point NERC doesn't have any standards on installed capacity, by statute. These are vestiges of regional standards that are only enforceable by contract, not by FERC. They may be easier to change than going through the whole NERC process.

Speaker: NERC has the ability to put in place emergency standards, but they are usually more like temporary mitigation actions.

Question: Reliability doesn't have a strict boundary between transmission and distribution. Similarly there is no jurisdiction over the economic regulation of transmission. It's not clear to me why state level representatives don't have input at NERC on the important issues. Why is it that we have not had an ability or even a mandate to be proactive in the construct of standards for reliability?

Speaker 3: Well, I believe there are state staffers on the Member Representatives Committee that provides advice to the NERC board. There's also a state sector within all the other committees. The biggest obstacle is the number of meetings, the amount of time in simply following everything. Even the biggest companies would have an extreme difficulty following it all without EEI and EPSA and the other trade groups to help out. There may be an issue that the state utility representatives on each committee don't necessarily seek input and provide output back to the rest of the state utility sector. That's a governance issue.

Speaker: This is related to a bigger issue for state commissions too. There's an interplay between building transmission and justifying it possibly for reliability purposes but the certificates of public convenience and necessity have different standards. How does one reconcile them?

Speaker: The current process is tilted towards extensive participation. For example, if a standard is proposed, if anyone makes one comment on it, it has to be re-voted and reballoted, right? It would be better if there were three or four standards that state regulators knew they should focus on out of 25-30 projects resources. Currently, it's spread too thin and they're all at various stages. There should be targeted changes in the standards that the state regulators can focus on.

Speaker: The statute says little about process or the arguable monstrosity that exists now. It simply says that the ERO [Electricity Reliability Organization] will provide some kind of opportunity for participation and comment. Some industry folks feel like they're not getting enough deference but it could be much much worse. Under the statute, in theory NERC could come out with its own proposal, solicit comment on it, and submit it to FERC – there'd be less deference there.

Question: There are system operators, relay technicians, and power plant managers who go to meetings and hear horror stories from their peers who have been audited, or FERC or NERC staff who say that if you don't do XYZ you're going to get a $1 million penalty. There's a strong urge to comply.

We've heard that because vegetation management has improved, then reliability has improved. Has reliability truly improved under a mandatory reliability standard regime? Has the industry given up optimizing their transmission system in their power plants because they are worried about complying with standards rather than aggressively utilizing assets? With new intermittent renewables, more transmission, including flyover systems, how do we balance reliability with the optimization of our assets? How does the industry go forward?

Speaker 3: Let's remember the Enron wars where they argued, "where does it say we need to have operating reserves?" The reliability regime is a constraint. We've also heard from utilities that it's 20% reliability improvements and 80% increase in documentation. I'm not sure it's commensurate with the amount of money we're spending. Clearly, operators are finding relays that are missing from their database. If they're not in the database, they may not be getting tested, and if they're not getting tested they may not operate correctly. There are definite improvements in reliability.

Speaker: It's very hard to get metrics to measure success because you are measuring a very small amount of failures. We haven't had another blackout; zero Category Five vents, and only one Category Four. A very serious event measured in millions of customers out. If we stay the course we'll have much better data in 10 years. Measurements on every level, including leading indicators and data on improvements. Then we can determine whether the relay documentation improvements result in fewer actual events. This is the early part of the process.

Question: Do we know if we're optimizing our assets as they exist today? Are we truly utilizing our infrastructure as it should be? I think we've gotten so conservative because of the reliability concerns that maybe those assets aren't being fully utilized, yet we're making decisions today to build more resources, more power plants, more transmission. Do we have the right balance?

Speaker: It's a provocative question. There's a sharp line between operating reliability and adequacy. It's an interesting question but the implications don't resonate with me. The consequences of bad events with reliability are so dramatically worse than the problems on the adequacy side. Adequacy is organized. It happens in a planned way. It can be recovered from quickly. Perhaps there's a heat wave and they have to go out and ask customers to use less electricity. That's much easier than when the system is being operated in a just slightly unsafe condition. There the implications may be that the entire interconnection is out. It takes 3-5 days to get back before the nuclear plants are back and there is normal operations. There's a bright line between reliability and adequacy.

There has to be a commitment to measuring operating reliability. In the end, that's the measure of whether we improve reliability. It can be simple metrics on fewer cascading outages and fewer Category Threes. There were two of those in the Eastern Interconnection last week. They were little traffic jams. Nobody got hurt. If it had been worse it could have been horrific.

Speaker: What does "optimize assets" actually mean? Is one optimizing assets from an engineering, efficiency perspective, cost of production perspective, profitability perspective, an emissions perspective? All of those are different ways of optimizing the assets.

Question: I would say yes to all of them. [LAUGHTER]

Question: Where does the previous ATC conversation sit relative to the bright line just described? Is it on the adequacy or the operating side?

Speaker: There are a set of procedures on the operating reliability side which draw a bright line in the ATC Standards. People spent 2 years trying to get them right – it's a challenging questions but they probably got pretty close.

Question: I have a policy question from a regulator's perspective. We all know the issues in electricity: instantaneous, must have, non-storable. It's all regulated. The industry is facing massive renewables, and the Smart Grid – what are the reliability challenges there? Clearly regulators are needed for standards. However we know there are politics on the regulator side too.

I give a real-world example. Some weeks back the Massachusetts DPU conducted meetings on the Unitel folks who dealt with a major ice storm December 11th and 12th. They lost 100% of its system and people were without power for 11 to 12 days in December. Over 1,000 people showed up at two days of hearings, almost 250 people testified, very angry. The next day the DPU gets a letter from a group of citizens in nearby towns who are opposing a transmission line that's been approved for NSTAR. They conclude that they would prefer to live without power for two to three days than to have that line. [LAUGHTER]

These are extreme situations. Regulators have to go back and explain the reasoning for those standards. I'm concerned that as the system moves towards greater flexibility for the new green grid we'll lose track of the standard. We run the risk of something similar to the financial debacle in the world. When they relaxed the rules in the financial world it eventually got to a point where all hell broke loose. How do we reconcile the new flexible grid with the necessity for real standards. A simple question.

Speaker: Yes. [LAUGHTER] Simple answer. Nobody wants cascading outages. Second, we all need to remind the nice people that it's very nice that they are willing to do without power for two or three days, but everybody else is not. They do not get to make the decision for the hundreds of thousands of people that will be affected if that line isn't there. It is a common good, and they don't get to veto that. In the end, the NERC standards and the regulators draw the line. They make sure we have a secure system and people can live.

Speaker: Some look at Smart Grid, decentralized energy, all have legitimate potential, but they argue new lines will not be needed. That might be true. In the meantime, until we get there, and only if these things work perfectly, we'll still need new transmission.

Speaker: That's why planning is so hard. Getting the assumptions right, especially in an era where things are changing faster than one can build, is extremely difficult. If you err on one side, much money is spent and on the other side there's deep trouble and the load cannot be served. At some point, you have to bet those assumptions and then see if you've made a reasonable decision. Folks doing prudence will have the last say. On can make midcourse corrections but they are tough.

Speaker: The policy debate has to address whether the industry redefines reliability to account for RPS standards, cap and trade, and other programs. Is the reliability standard part and parcel of those standards? Do we give that new charge to NERC and the regional organizations? That issue has to be addressed up front or we'll be playing catch-up.

Speaker 2: The question is still, can you tell a landowner that reliability standards require the construction of a line? The other way is if the line is not built then operating reliability rules would result in those customers being taken out of service to protect the system.

It's more complicated with ATC because there's a chicken and egg thing going on. There, one would define the operating reliability procedures for that area in the marketplace. It's challenging because they are not independent of one another. They're seamless in terms of operating reliability versus the impacts of adequacy and a market. The operating rules themselves are always designed to address the hand they're dealt. They shouldn't be writing rules that force behaviors upon markets, right?

For instance with renewables there will be a task group. Those stakeholders will determine what it takes to have operating reliability with variable generation-like wind. They can address variable generation via small balancing authorities. They'll integrate short-term load forecasting. My point is that operating reliability can be determined once there is a system.

Speaker: Generally, is that the difference between passive reliability standard creation versus active forward-looking, anticipatory reliability standards?

Speaker 2: Yes, that's the hope. NERC or the ERO should respond to policy choices and be able to anticipate what has to be imposed on the system from a reliability perspective. If it's 20% wind, well, how would they operate it? What would it have to look like? How would system operators maintain the voltage?

Speaker: There are transmission planning standards which may be violated if a line is being planned. When people go for certification, they probably held up the NERC planning standards and said we need to ensure reliability. This line solves these things and the other seven alternatives are more expensive. NERC is not in the business of making those standards less rigorous.

Question: Assessing the relationship between the FERC and NERC is the wrong question. The reliability of the power system in this country is among the poorest in the developed world. It does not reside in the interstate local system. It resides in the local distribution systems and they are very poor. NERC and FERC are always perceived as stepping on the toes of state's rights and the freedom of the local commissions and legislatures to decide how they want to deal with reliability of that level has been an ongoing problem. How does one deal with this issue?

Speaker: The law is absolutely clear and it gives federal authorities no authority whatsoever.

Speaker: We have to change the law.

Speaker: For distribution, it would require a change in the law. The needle has swung so far over toward adequacy. One hope is people will make different choices about how much they want to pay for different levels of reliability. They ought to be able to move back and forth, depending on what they can afford. There would be a different answer to that question in New York City than another location.

Speaker: There are three options. Migrate it away from the states to FERC and NERC. Second, impose a federal standard on the states. Or, third, muddle through. I expect we'll muddle through.

Speaker: It would be a mistake to federalize reliability of the distribution system. For instance in a system like Chicago, they have different levels of reliability in the loop and the high rises and transportation than in the semi-rural areas. The states should be dealing with it in cooperation with the utilities. I'm sure that neither NERC or FERC wants to get involved with tree trimming in a suburban village where residents don't want their trees trimmed but they'll come down in a storm. That's so local.

Question: I don't suggest federalizing reliability but there should be some minimal standards of reliability. Many residents have a great deal of dissatisfaction with the standard of reliability and service they get. They are quite willing to pay a tiny increase to raise the standards of reliability. It's important to the national economy.

Comment: This is not about shaving the edge of your electricity bill. This is about creating jobs and competing in a global government.

Question: Here's an anecdote about vegetation management in Alabama. I'm at a conference and get a message on the BlackBerry in all caps: "woman ties herself to tree in Jacksonville." [LAUGHTER] The power company was trimming her tree, and she tied herself to it. The local court ruled that the power company could not trim that tree down. To tell you how powerful that power company is, shortly after that we had a tornado and the tree blew down on her house. [LAUGHTER]

On a serious note, what difference do you see with the new administration, and changes at FERC in the next three years for this whole issue of reliability and the ERC's?

Speaker: I don't think there will be a lot of change. Section 215 is not on top of the new chairman's list. It's too technical for most commissioners. However, the resource adequacy and the non-215 reliability involve more integration of wind. The question of reserves, market rules, and who pays for it will get more attention there, but I'd say less change with 215.

Speaker: We'll see debates over cyber security and what role the various agencies of the federal government should have in the event of the credible threat. One of the big issues that sank previous legislation was giving FERC a DOE authority for cyber over the local distribution system.

Speaker: It's about how much more will be added to the plate of the organizations that are involved. The agenda is about the role all of those will respectively play in interconnection wide system, planning for transmission siting cost, recovery, etc.

Question: Transmission planning standards tell us what needs to be built. Operational standards tell us how to operate the system reliability. But if there's new planning entities, where's the gap? What's missing now in terms of planning?

Speaker: Two things, geography and cost allocation. The existing planning entities don't have a big enough geographic footprint and the cost allocation decisions they're making will not facilitate the big lines.

Question: Operational constraints have to be put in place across a broad region beyond the normal planning process. There's no vehicle today for larger interregional projects beyond a FERC Presidential Permit.

Speaker: Well, if we're talking about delivering hydro from Quebec into New England then we're dealing with neighbors. It's not always easy but it usually works out. Alternately, if we're discussing an administration grand plan to solve everything is to take all the wind in the Plains to New York City. [LAUGHTER] I don't know if that's right.

Speaker: With a short stop in Chicago, too.

Speaker: If we're talking tens of thousands of miles of EHV across the country, the current organizations barely play with each other now. It gets even worse when people are trying to decide who should pay.

Speaker: Our existing organizations aren't really well-suited to deal with 10,000 new miles of EHV. Further, it's an open question whether we really need 10,000 miles of EHV.

Speaker: There may be a plan to build 1,800 mile DC lines from North Dakota to New York City. But New York is saying we have plenty of wind in Upstate New York. New England saying we have plenty of water up in James Bay. A huge line creates an arbitrary statement that we like Dakota wind.

Speaker: Well, an Eastern Interconnection regional planning study would do the same kinds of things that NERC does with its assessments of the bulk power system in North America. They do it, evaluate it, everybody can see it, and reference it. It has no authority, nobody approves it – it just a document for deciding what to do. It can be very helpful. If it has an approval process or a governance structure, that can be harmful. Some sort of reference case is helpful though.

Session Two.
Smart Policies for Smart Grids: What, in fact, are the Policy Issues?

"Smart Grid" is a term du jour. Proponents see a gateway to a host of desirable results: more efficient markets, better end use efficiency, emission reductions, green jobs, energy independence, security and reliability of supply, better service quality, and better information for reduced costs to consumers. It is clear that "smart grid" means different things to different people. For some, a smart grid makes more efficient use of existing transmission assets, perhaps above initial ratings and for more efficient dispatch. To others, a smart grid means a distribution system that is fully able to communicate with customers and their electric end use devices. Finally, to some, a smart grid means new generating resources, especially renewable ones, to load centers.

How should "smart grid" be defined? What incentives, if any, should be provided to invest in "smart grid"? Regulatory incentives? Tax incentives? Public investment? How should regulation and market design be altered to encourage "smart grid"? Are consumers sufficiently motivated and educated to take advantage of the opportunities "smart grid" offers? Is there a "chicken and egg" problem in regard to motivating consumers and technology investment? How do we determine the beneficiaries who should pay, or, alternatively, should we simply socialize the costs across the system and not concern ourselves with identifying beneficiaries of cost causers?

Speaker 1.

I'll talk about these issues from an economist's perspective. I hope to do three things. First, define what a smart grid is. Second, discuss why there's so much psychosis amongst utilities about the smart grid. Third, if this is such a smart idea, where's the money? And how do we count the money?

What's a smart grid? People talk about smart grid and don't define their terms. The biggest user of electricity in the U.S. is the electric utility industry itself. They use more of the product than anybody else. So one of the smart grid ideas is to tackle this problem. A smart grid would be technology that allows plants to work more efficiently and to get improvements in the transmission distribution system. This could be 5% improvements that would affect 94% of the total load. A big impact. This could include sophisticated sensors on the transmission distribution system. These communication mechanisms used with sophisticated algorithms would get much more granularity of how the system works. One can anticipate a voltage sag or harmonic disturbances and preempt them. Some people call this process self-healing. So utilities think of a smart grid as investments on the grid, not in the household.

Others believe a smart grid will enable distributed generation and reduce reliance on central generation. It would include fuel cells, gas turbine, and photovoltaics. This is on the other side of the meter. The smart grid would accommodate all these devices, sending power when they want to.

A third definition is inside the home. It would liberate the consumer from the yoke of regulators. It would include real time pricing and allow many decisions. It would allow many kinds of pricing programs. It would be a transaction economy like eBay, but it's vBay. Then there's hyper-efficient appliances, many of which are compatible with being dispatched often. Things like LEDs and appliances that can be turned on and off with some frequency.

About 92% of American households are within one mile of an ISP but only about 55 or 60% of homes have Internet. An internet system needs to go beyond 60% of the households in a region. Thus, utilities who are thinking about smart meters for their smart grid are considering their own communications systems. This vision includes broadband over power carrier, or mesh systems, or radio net systems that can communicate very quickly both ways. Since everyone is communicating anyway, why stop at the meter? Thus the meter could be the hub or gateway into the house. It can handle messages, and control devices. It can run diagnostics and tell you when the motor of your refrigerator's about to fail. It can send real time prices, send a bid offer on a call option to sell electricity.

The implications of this are at least a change in scope if not a scale change in how utilities work. The utilities have never been behind the meter before. There will be tension between those who want to provide this information via already existing internet wires versus utilities who will want to add communication capabilities. This aspect of the vision means thinking about how the future utility will look.

This is such a good idea, the benefits should be abundant and easy to find. A lot of people mention operational savings. They also include customers are happier and have choices. These are challenging to even think about, no less measure. Operating Income? If the utility has cost savings, there should be no rate change.

The problem is that most smart grid programs are justified on a combination of operational savings and societal savings. The societal benefits are enormously difficult to quantify and to measure. Thus the question of who pays gets very difficult.

A consortium of utilities in Ohio has been looking at the benefits of the smart grid. One problem is there is a lot of double counting, as well as pure speculation. The mutually exclusive and collectively exhaustive set of so-called societal benefits include things like reduced outages, increased national fuel security, consumer choice, allowing demand response, and the associated reduced expenditures. Monetizing this is hard, how do you take externalities and turn them into dollars?

Another metric is critical fee pricing or peak time rebates or critical peak pricing. Studies suggest that enabling technology under CPP provides very high benefits. However it only works by offering people huge amounts of money. How does one justify paying somebody $1.50 per kilowatt hour? So there's lots of problems to be solved in demand response, but we seem to be relying on it now.

So how does the industry justify the gap in smart metering or smart grid and the costs to implement it? If it's agreed that a demand response program is going to close the gap, does the utility have to be responsible afterwards to make sure that there's that much demand response? Should that be part of performance clause? This is the big question for the industry.

Speaker 2.

When I discuss the smart grid, it is about resource, energy, consumer, operations, and asset efficiency. I won't talk about meters, for instance. Let's consider what actually gets deployed in the smart grid. The few things that are ubiquitous will get deployed across the country. Especially where the technology is right, the policy is consistent and the consumer is on board. All three of these things are critical for adoption.

Let's consider two examples where this might happen. The first is the plug-in electric hybrid. NREL's [National Renewable Energy Laboratory] study shows that if we deploy plug-in electric hybrids they reduce every emission in every part of the country except particulate matter in the central US. It replaces an inefficient engine with a more efficient power plant. Duke did a similar study with a different conclusion. They concluded that deploying electric vehicles will increase the bill for generation and transmission and that it wasn't a good deal for the environment.

The primary difference is when you charge. If you charge at night, you get the benefits. If you charge during the day, there are incremental costs. If you charge at night, 80% of light duty fleet could be powered by the existing infrastructure. The government is giving big incentives for EVs and PHEVs [plug-in Hybrid Electric Vehicle]. There's consumers that are ready, money in the stimulus package, and money to build battery factories. Does the industry and regulators enable plug-ins to repower at night? There is an enormous policy need to create the right night incentives.

Second, let's consider PV [photovoltaic]. Since 1974, the cost of PV on the logarithmic scale has had a continual price decrease. There are new technologies coming online, specifically Thin Film, Cadmium Telluride, that will drop the cost of PV. Statistical modeling on the cost decreases and on utility rate increases show that PV will be at grid parity in the US in places within five years. That excludes CO2 costs and incentives. Incentives in Arizona get 10 to 25% internal rates of returns for people to deploy PV in competition with their distribution utility right now. Wal-Mart's deploying PV on their stores, and big boxes are big customers for distribution utilities. Wal-Mart isn't doing it because they can make an internal rate of return, it's about cash flow. Any big box sore that puts PV in their mortgage can be cash positive on day one. It will change how generation is done in this country. They'll be in competition with the grid.

From a regulatory view, either find a way for the utility to be proactive on the PV side or you wait for this stuff to get deployed, in which case the utility has the worst possible outcome. They lose generation revenue and incur all the cost of having distributed generation in their grid. That kind of decision integrates public policy, consumer interest, and technology at the same time.

A basic scenario for 2025, shows more than half of the main plant generation in this country will be intermittent, renewable generation. A large percentage of this will go into the distribution grid. In Germany, most wind is in distribution. The country will have to figure out how to deal with renewables because they are coming.

There's huge benefits from a societal view to having demand side reduction if one reduces peak and defers investment. Data by GE shows millions of tons of CO2 avoided, 75,000 MW of generation avoided, and savings in the trillions with utilities performed with 20% demand reduction. These benefits really appear case by case by utility. They are not ubiquitous nation-wide.

There are nine clearly statistically distinct consumer groups in relation to the smart grid. Each group will react differently. Google's done a lot of this research when they launched the power meter; they want to make money. It's not because they're being altruistic. They figured out that there's a big part of the consuming population that may be willing to pay for information about energy use, energy control. They understand that there's a segment of the population out there.

Given this should utilities continue to be regulated in the same way? Do they tap into the value streams that are going to be created as these smart grid technologies get deployed? Do they tap into part of Google's value stream? Part of this will be determined by what gets rate based. Will the utilities get to see an economic incentive?

From a regulatory perspective, the utilities have to deal with the inevitable. EVs are coming and they need to charge at night. It could be peak critical pricing, or some other incentive. Second, PV is coming with embedded generation. This will require distribution management, more transmission protections. Distribution will look like transmission. There'll be two-way power flows.

With demand side management, the only people that see the benefit are the consumer advocates and the PUCs. So the PUCs have to be the custodian. There should be a focus on societal benefits. The lower costs at night to charge via easy interconnect standards not metering. Efficiency is a byproduct of doing the rest of this. If you plan to embed PV, you get grid efficiency because you get full bar control.

When NREL looked at charging cars at night, they figured out that electric consumption in the country goes up if you start to replace oil with electricity. There's a nice unintended consequence of having the cost of electricity potentially go down for consumers because you're selling more megawatts on a capital installed base that doesn't change.

Speaker 3.

We have all been beneficiaries of incredible change over the past 20 years in terms of digital communication technology. Our BlackBerries and laptops is one manifestation. This transformation is coming to the electric power network, particularly with respect to consumer-centric parts of the industry. We need to think about smart transactive grid. If it's not a transactive grid, it's not smart.

We are seriously facing a paradigm shift. What the digital technology revolution of the past 20 years has done to us is the potential to decentralize coordination. This is bottom-up coordination of agents who are dispersed throughout the network. It's another way of organizing and coordinating our network instead of the imposition of hierarchical control. A decentralized capability of two-way communication makes it much easier to have competitive markets. We need to broaden our thinking to think of the electric power network as not just the physical assets, but also the human agents in this distributed network.

What do I mean by transactive? Everything that we do in our entire lives, whether it has anything to do with electricity, involves a mutual exchange of value for value. One can think of that as a transaction. When I agree with my spouse that if they do dinner, I'm going to do the dishes, that's a mutual exchange of value for value. What transactive ways of thinking can conceptualize the electric power network as a distributed market platform?

So the power network can connect producers and consumers. It allows us to engage in transactions through contracting and renegotiation. It helps folks see inefficiency in our network and also see the role that transactions play. Many regulatory policies create transaction costs. Digital communication technology is really good at reducing those transaction costs. We've all seen it, we've all bought from Amazon, or sold on eBay. Those kinds of transactions can and should become a reality in terms of the electricity consumer's experience.

Let's consider a home consumer gateway portal. So imagine a screen on your wall at home, and one can control their electricity consumption of all of the different applications in the home. It's the HVAC, lighting, laundry, appliances in the kitchen, home entertainment, even blinds that go up and down. They can control all of these, get a web forecast, program all of these devices to respond to something, to go up or down at a particular time or respond to various situations. If the electricity price goes up from 9 cents to 12 cents, knock the temperature in my water heater back by 5 degrees.

Consider the plug-in hybrid example. Let's say one has solar panels on the roof and really doesn't want to use fossil sources. One does their car charging at night. One can program the home system so that once the capacity of the solar panels is used up then instead of buying fossil the uses in the home are dialed down; reduce your demand. One can respond to the fuel prices but also the fuel mix. There are all sorts of different things that one could program in devices to respond to autonomously on one's behalf.

A recent research project to test some these ideas was the Grid-Wise Olympic Peninsula Test Bed Demonstration Project. They tested a narrow stream of these potential functions and capabilities. Household residents had price-responsive thermostats and water heaters. They could program them to respond autonomously. They had a retail contract choice. Three choices: fixed price, time of use with a critical peak, and real time price. The combination of the technology and the contract choice gave them a lot of savings and also created high system reliability. There were never any unplanned outages during the duration of the project.

Some have argued that real time prices are too inconvenient for residential customers. Or the concern that customers are not home and the price shoots up and they'll get stuck with a huge bill. This has been one of the justifications for not having real time prices.

The research project attempted to create a real time market that would be very inconvenient without the price responsive technology. They used a double auction market design which is highly economically efficient. It converges equilibrium quickly with low levels of dead weight loss. In a double auction market you have buyers submitting bids and sellers submitting offers simultaneously. A computer algorithm ranks the bids in decreasing order, ranks the offers in increasing order, finds the market clearing price and charges that price to all consumers, and then, you know, sells at that price to all the sellers. The project did this in the residential market every five minutes for a year. They loved it. The real time price [RTP] group had peak consumption fall by 15 to 17%, depending on how you measure it. The average customer across the whole group saved 15%. The RTP group saved the most, close to 20% on their bills, mostly because they could program their price responsive technology to anticipate for market changes.

This system has diverse consumers with their own heterogeneous preferences. It's a network of heterogeneous agents with diffuse private knowledge. The data generated from this indicate that it's a self-organizing coordinating system. It means this real time market was a very efficient market. It self-organized because of this process of decentralized coordination. The individual actions of all of these distributed buyers and sellers coming together with the technology through the real time price market create a decentralized coordination. I'm arguing that decentralized coordination can create the physical reliability historically associated with hierarchical physical control. There'll be another project at the Bonneville Power Administration that will be like this project on steroids to look at this issue.

While these are potentially profound results, there are cognitive barriers to change such as status quo bias, and both individual and organizational inertia when it comes to change. These are the things that need to be addressed, what is the real potential for this transformation and what are the barriers?

Question: In the Olympic study, did the participants have a certain educational or financial level? Or they're all just a mix of regular people?

Speaker 3: That's an important question. This was a field experiment, there was no random sampling. Demographically the population's pretty homogeneous. They're mostly middle-income retired couples that have retired to the Olympic Peninsula because it's gorgeous. Future research will extend the demographic reach.

Question: I'm assuming that this took place in a regulated bundled utility.

Speaker 3: Yes, it did. However, I'm a big fan of restructured markets. The implications are similarly profound in a deregulated environment where the retailers may have an incentive to help customers get aware of these technologies.

Speaker 4.

I'm going to address some of the issues involved in implementing the smart grid. I'm going to try to address some of the different regulatory strategies, problems, and approaches that can be used.

Let's start with some basic facts. Everyone who engages in a transaction, buyers and sellers, are doing and pursuing their own best interests. Utilities are generally not in the business of slowing down the speed of their spinning meters. That's the premise I'm beginning with and the challenge that regulators have to deal with. Utilities don't want to reduce sales but consumers want lower prices. Given these tension and concerns, how do we get the smart grid moving?

There's the customer side of meter in smart grid and the operations side. There's been less attention given to the operations side and it gets more complicated. The introduction of a lot of renewables and alternative advanced energies complicates things.

For example, how does one accommodate intermittent and variable generation inputs into a smart grid when it's already hard to integrate them into the grid as it currently exists? Recent conferences addressing problems in dispatch, ancillary services, voltage support, spending reserves and so forth demonstrate that these issues are problematic. It's unclear how one can cope with those issues within the context of the smart grid or an expansion of the transmission system, for that matter. We've heard about decentralization but a centralized system could address different states with different renewable portfolio standards that we're going to have to try to accommodate within the smart grid. Different states have different benchmarks for implementation. Some states like Ohio have laws that call for the production of renewables within their state. These are real problems for a smart grid.

Renewables are more effectively deployed when they're deployed in a large geographical expanse. The more decentralized the resources are the more benefits of diversification go to more areas. The bigger the footprint of smart grid on the operations side, the better the benefits on the operations side without taking anything from consumers. This approach gets us closer to general equilibrium, rather than partial equilibrium. Partial equilibrium analysis too often dominates the discussion.

For instance, ethanol is a good example. Everyone thought ethanol was just going to be the wonderful replacement for fuel, and maybe if gasoline was five bucks a gallon, it might be. However, in a general equilibrium, the price of corn went up and other food stock went up with respect to farm animals. Ethanol incentives had a variety of negative effects.

Now let's compare smart grid and renewables. Everyone liked renewables, but I think smart grid in a general equilibrium sense is much easier to defend. First it is being implemented in steps. AMR [automatic meter reading] is current, and it will translate into AMI [advanced meter infrastructure], step after step until we have what we've been shooting for all along, and that's price-responsive activities by consumers who can lower their bills. This approach means we can stop if we have to if problems start to emerge.

How does one implement all this without a battle of wills between regulators and utilities? One way is to pass laws, like renewable portfolio standards at the state level. Laws are hard to undo, particularly when technology is changing. They are also hard to tweak, and they invite powerful interests like the utilities.

I'd argue the regulators should be the ones empowered to move smart grid. The utilities interests do not lie in the smart grid and their culture remains relatively static. The regulators need to help ensure the utilities find some benefits, so that customers can find their benefits.

The Department of Energy has $4.3 billion from the stimulus fund in matching funds for utilities. There's a lot of other money involved too in conservation, renewables, that could be tapped by utilities which result in real dollars. It pays for the meters and infrastructure. The lost revenue obviously is the thing the utilities may be most concerned about. We can think in terms of the fifth fuel. It takes place when utilities recover their lost revenues, but also when customers are otherwise urged to conserve. This is not real popular with regulators. For example, how much of their foregone revenues should be recovered? There will be big fights over stranded assets.

Decoupling, on the other hand, assumes the recovery of fixed costs. It accounts for the fact that fuel is a significant driver in electricity itself. In Ohio they've used the straight fixed variable in the area of natural gas distribution. There's still a question mark as how it works with the electrics. There is a concern that it reduces demand for the utilities, and ultimately there is not a lot that regulators can do about that.

Performance-based regulation may be a little bit more palatable. Regulators can allocate higher returns for reconfiguring load curves via an investment in smart grid. This approach may feel less painful for utilities.

Finally, we can always use the bully pulpit to get smart grid moving. Utilities always need something, whether it's a rate request, or some service quality issues that need to be dealt with. Regulators have the ability to push back and forth with utilities. That may be a big part of the process.

Question: In the Olympic Peninsula case, please distinguish the difference between "time of use" and "real time." Real time is the price every five minutes. But is time of use just simply a block of time that's predetermined? Is that the difference?

Speaker 3: Yes, exactly. There's a real question about the amount that the digital communications technology and regulatory policy are needed to implement dynamic pricing? If dynamic pricing is time of use, it's not so important. In the Olympic Peninsula, time of use was 6-9 a.m. and 6-9 p.m peaks. The customers know that ahead of time. They make their plans and that's not going to change. More truly dynamic pricing where prices fluctuate on a much more granular scale and in ways no one knows in advance really needs price-responsive end-use technologies. They become really valuable because one can use them to behave on your behalf.

Comment: Culture is very important. This is a legacy system based on maximizing supply, dump the power at the doorstep, and get those lights turned on. A regulated monopoly system was the right system for that 50 years ago.

One of the fundamentals to change for the smart grid is that the Iron Curtain of the meter has drawn a hard line between supply and demand. Breaking down that Iron Curtain and allowing continuous free flow of information, pricing, demand and energy in both directions is what we must build for. It is not needed or even wanted today but it is the future. We must enable the third parties and entrepreneurial companies to begin to play in this game. The benefits in every analysis where stakeholders have sat down with communities and looked at the benefits of a smart grid transformation on both sides of the meter show multiple benefit-to-cost ratios. It's about job creation. It's about operating in a globally competitive economy and being in an advantageous situation with respect to our infrastructure. It is beginning to look at electricity not as energy, but as the lifeblood of our economy and quality of life, and moving this business from a dumb commodity business to a smart service business. We can't begin to imagine the service that will be created when we open this up and the value of those services.

A key issue is regulatory staffs. The regulatory staffs like being the customer. Regulatory staff won't be needed as much to protect customers if they're empowered with smart technology and well-designed markets. This can be smart, dumb, old, rich or poor customers. We still need regulators but not the same structure of regulation.

Question: There's a cost associated with this and how's it going to get paid and by whom? Why can't we make this a sustainable business for utilities and others? Why can't we let them recover costs, earn a return? If figure that out won't it deploy it a lot faster and with a lot more innovation?

Speaker 4: It is sustainable and workable within the context of a utility business plan. Presuming that the benefits are there, then it would be recoverable. That's reasonable. There will be utilities that argue that they're vertically integrated, regulated, haven't spun off generation and they're stranding a ton of assets because demand is being reduced. That's an onerous scenario. Other utilities may not be vertically integrated or their assets are pretty well depreciated. Then recovery is allowable and reasonable. Most reasonable regulators have every intention of granting recovery to the utilities based on the assumption that at the end of the day, the customers are going to be better off. Stranded assets will have to be addressed. And Congress is putting $4.3 billion out there in play.

Speaker 3: There is a question of what happens to the organizational structure of the firm as technologies, firms, and industries evolve. As technological change has occurred that reduces transaction cost. The adaptation of the industry structure changes the transactional boundary of the firm. What does that mean for the electricity industry? We the vertically integrated, regulated utility which is 100 years old. If we look at technological change in other industries we can see how these changes might happen here. We started to see that with EPAct 1992, wholesale markets opening, putting the GE jet engine on a platform, all of that kind of technological change coming in.

This digital communication technology contributes to another push for that evolution of the transactional boundary of the firm. The concern is that our regulatory institutions solidify against that adaptation and don't allow firm structure to adapt to unknown and changing conditions, or the evolution of technology. Sorry to all the regulators. [LAUGHTER]

Speaker 4: That's because you don't sign the orders that raise rates. [LAUGHTER]

Question: In the Olympic Peninsula study how did they address the supply side of the five-minute pricing. The customers were bidding in through technology, but how was the supply bid in?

Speaker 3: Part of the motivation for the Olympic Peninsula study was constrained distribution. They're living in this absolutely gorgeous part of the world and they need to build a generator, or build more wires to get more power. Neither of these options was going to be easily done in that area, to say the least.

The households that participated were strung along in different communities along the northern edge of the peninsula. They were aggregated into a virtual distribution feeder. Generally, they buy power from Bonneville. There were also 3-4 smaller sources and some distributed generation capacity. In periods of high demand, the other sources were able to kick in and power would be shuttling back and forth both between Bonneville and the DG in those five-minute increments. Both supply and demand did respond in those small increments.

Question: OK, so here's the policy question. Let's assume smart grids are deployed in a market. What percentage of the load is needed to participate to make it a fluid market and ensure the five-minute price intervals are accurate? If one achieves that threshold, can price caps be relaxed on the supply side? Can you relax requirements for scarcity pricing and all other aspects that are troubling the market today?

Speaker 3: Yes you can relax them all. It's basically about the consumer behavior. One of the speakers in the first session characterized aspects of a good smart grid program as "set it and forget it." A consumer can program their demand function into the thermostat and water heater. Then they go and live their life. Empirically, the market clearing prices weren't changing in five-minute intervals. Hours might pass with the price being the same. However, every five minutes, 130 households with 260 devices each have a standing set of bids. You know, for this price I'm willing, for this amount I'm willing to pay this price, for this amount I'm willing to pay this price and so on. The engineers had a complete field day turning the thermostat settings into meaningful price signals. So in any five-minute market interval, all of the devices are still making bids and all the suppliers are making offers.

Question: Do smart meters need real time rates? Do they go together?

Speaker 3: I'd pick smart [real-time] rates over the smart meter. If consumer's know there's a price signal going on they'll use rules of thumb even if they don't have a smart meter hanging on the outside of the house.

Maybe there's a retailer who can take advantage of my existing Internet coming into the home and just slap a device to communicate the price information to me that way, I don't need a meter. But I do need a price.

Speaker 2: I've seen demographic data that shows there's nine segments of consumers here. They're not all going to sign up to play. Some companies are designing energy home management products that will retail at $600-800. That excludes a lot of homes.

Security companies anticipate putting energy management in their security offering. The security companies are trying to figure out how to aggregate, load and bid in where there are markets like the Northeast. There's a lot of different ways to play, but not everybody is going to play. What we don't want are newpaper headlines about the person who's on a fixed income that is forced onto variable rate pricing and has tremendously bad outcome that makes the front page of the newspaper. You know, they now pay a huge amount for electricity and they used to pay a small amount. That would be a terrible outcome for the industry.

Speaker: A smart meter and a smart grid are the same thing. A smart meter without dynamic pricing defeats most of the value you get from it.

Speaker: I think you need to do both. You've got to change the meter too. Without it, no one can send a bill.

Question: Not all utilities are going to be resistant to smart grid technology. California is a decoupled state, and their utilities don't make any money associated with the meter spin. The smart grid is an example of a great investment opportunity for a utility in its infrastructure system. What's missing in this story?

Speaker 4: Well California's a little different, as we all know. [LAUGHTER] Generation is not a big part of the equation in California. If you're vertically integrated with a lot of rate-base generation, it would make a big difference if that stuff was stranded. If a company is counting on returns from their generation and you don't get it, it's a tough situation.

Speaker: There are some vertically-integrated utilities that embrace demand-side management in a big way. Florida Power and Light is a good example where they're generation constrained, load growth is big. They have one of the ten largest demand-side management programs in the country. They're actively suppressing demand, but they're in a unique position too.

Question: New Jersey's basic generation service as another place where we're seeing customer behavior change because they are linked to prices. They are able to use the price-quantity experience to help with system reliability.

I'm concerned about feed-in tariffs. They are take or pay, got to have it, and no locational aspect to it. There's no price or time base. How does this fit into the picture?

Speaker 3: I have concerns about feed-ins also. It's an administrative decision to pay X to get a bunch of solar. The feed-in tariff in Spain has been tagged as one of the potential causes of the dysfunctionality in the European carbon market. It's poorly designed in any case. The Spanish feed-ins induced huge amounts of investment. They got triple what they forecast in terms of investment. It's contributing to negative consequences in other parts of the capital markets.

Speaker: A lot of these are state policy driven. Japan has had huge PV feed-in tariffs and Sharp became the number one PV supplier in the world. Germany put in big feed-in tariffs for PV and Q-Cells became one of the top PV suppliers in the world. This is about global competition in the marketplace and industrial policy. It's about nations building industries to compete in the future. It's not about generating electricity economically.

It's different with wind because wind has matured enough and the players have gotten big enough. RPS standards and carbon policy also create big incentives although the exception there is offshore wind.

Question: How smart do you need a meter to be? In Illinois the residential real time pricing uses meters that are smarter than the traditional watt-hour meter but they're not truly smart meters in the sense of having two-way communication. They do record hourly energy use. Only customers who choose to join a real time pricing program get them. The overall cost is lower than putting out smart meters and only having 5 or 10% of the customers take it. However, because they are not being rolled out en masse the higher cost of the 2-way communication can't be justified. It may be a nice half-way starting point.

We heard how big, sophisticated users like Wal-Mart are using PV. How will consumer-side investments needed for smart grid functionality going to get financed? Not everybody can restructure their mortgage to get the right technology. Can utilities use on-bill financing? Do we want them to become lenders? What is the right financing mechanism?

Speaker 4: I'll take a quick shot at it. I think that first of all in some sense the utilities can be bankers. There's always expenditures that are being made, collections that are deferred with carrying costs. There's no reason why meters cannot be deployed, or carried and deferred and ultimately collected. To some degree there will be some socializing, which means you're going to pretty much going to have to make sure the meters are pretty universally deployed.

Speaker 2: Well external companies may get in on the game. DSM in PJM brought Converge and other companies. Now security companies, ADT and others, are working with them. There are mechanisms to get third-party investment by having the right policy.

Speaker: This is not impossible if they can work out a deal with the utility so that they get to pay back over an extended of time rather than overnight. If communities and utilities cooperate as partners as opposed to prisoners, that's an important part of this cultural transformation.

Question: Consider my Internet service, it's Verizon FIOS. Not all my neighbors have it though. They didn't have to gang meter the street. They just did me. Then I went to Best Buy and bought a bunch of devices to set up an in-home Ethernet system. I never spoke to Verizon when I did this, but instead got the devices from a third party.

Now there's a sort of smart system in my house. What is the critical mass, what are the economies of scope? Why does it have to be done by the utility? Why can't it be done by Wal-Mart? Why does it have to be done for everybody? Why can't it be done just for the ones who want to get it? This let's folks self-select. It can be set up as opt-out instead of opt-in. We don't want retired people to be forced on this. How do these pieces fit together?

Speaker 2: The vision you just discussed is totally plausible. The problem is for the utility. First they have to select the technology that allows them to mix and match the meters. In one place there's a 30-year-old mechanical meter, the next residence is a drive-by read and the next one is a smart meter. That's the technology planning thing that needs to be done and can be solved.

Question: But I can't go to Wal-Mart and buy a meter? Why not?

Speaker 2: I'm sure companies would like to sell meters through Wal-Mart and make them all different colors to match your house.

Speaker 1: There's a whole lot of focus here on the meters. One can decentralize so much that you wouldn't have to depend on it. The meter could just give the utility a reading. When in fact you could have smart appliances, chips in dryers and washers. There's a lot of stuff that can be done. You could plug something into your wall and then in turn plug something into that which will communicate with a box outside; not the meter, bypass the meter.

Question: I'm looking for something analogous to the fiber optic on my street.

Speaker 1: The analogy would be a box up on a pole not far that can communicate with your washer.

Speaker 2: There needs to be a communication backbone that the meters need to talk to in some way. The choice to to select in, whether you go to Wal-Mart or whether you call to the utility, that clearly can be done now. Water companies do it all the time but electric companies don't. In some places one can have a separate water meter to water your lawn, you pay the utility for the meter but then the lawn water meter gets a lower rate because the water doesn't go back to the sewer. That's the kind of potential choice we have.

Speaker 3: Protocols are tricky. The legislative story, under EPAct 2005, Congress stipulated that the metering function goes with the wires company regardless of the state restructuring legislation. The property right to that future transaction, future revenue stream was given to the wires folks. It would be nice if it were like cell phones. If we have competing retailers, you come to me. I give you a plan and if you sign up with me for two years, I'll give you your spiffy meter for free. But you've got to sign up for two years. For that you need a) you need a competitive retail market, and b) the metering function has to be open to competition.

The Grid-Wise Architecture Council does some good work on interoperability principles. They help design protocols to make sure that all of the different devices can talk to each other across entity boundaries. Since the Energy Independence and Security Act of 2007, Congress has stipulated that NIST [National Institute of Standards and Technology] will serve as the focal point for the standards with organizations like Grid-Wise kicking in.

Speaker 2: In the stimulus package there is a provision to bring broadband to the rural communities and underserved communities. There are meters that run communication technology. Telecommunications companies and utilities can work together, and the utility doesn't bear all the cost.

In one situation, Sprint wants the pole tops that the utility has. In the meter there's a router. So that if you order Sprint broadband Internet service, they actually don't send any person out to you. You plug into the wall. There's big value there. It's a nice time for a one-time marriage between telecommunication companies and electric utilities to bring the most advanced communication technology to rural communities. It could be done in urban communities if the right agreements are made.

Question: You argued that smart grid trumps renewables. Is that from an investment standpoint, an either/or proposition or what?

Speaker 4: No, it's not either/or. It's a general equilibrium sense. With renewables, we don't know what's going to fall off the cliff and what's going to make it. There's just so much involved with big resources and big implications. With smart grid, it can be done incrementally, the investment isn't lumpy, and we can work out the bumps along the way. AMR is better than the status quo. And AMI is better than that. Each increment brings benefits. Further, it's all about demand reduction, conserving, and better efficiencies. Overall it's simply that smart grid is easier to implement, is more about efficiencies, and has fewer risks.

Question: This conversation shows how wide open this field is. It's involved everything from feed-in tariffs to fixed-rate versus regular decoupling to renewables versus smart grid here. There is still not a consensus about what smart grid means and that is important.

The RPS is intended to do exactly what you're talking about. We want renewables, but we're not going to pick which technologies. They do it under a competitive environment and bid out. The public doesn't lose if the contract falls through, but we get a growing incremental percentage of renewables on the grid. There are variability problems, but there are emission benefits to every incremental renewable addition.

Speaker 4: Yes, but they cost money. The more you use, the more they cost.

Question: But so does smart grid technology.

Speaker 4: The smart meters are an investment that pay for themselves. They provide the opportunity to look at dynamic pricing. They allow less consumption, be it renewables or not.

Question: In both cases you save emissions. And they both have investment requirements. What is a more cost-effective, emissions-reduction strategy? It looks like we're going for both. Can't one have renewable strategy that's incremental and allows for competition without sunk investment.

Speaker 4: I'm not convinced we have the optimum mix of renewables.

Moderator: Everything should stand the market test. However, the smart grid can be a huge part of the ability to manage the intermittency realities of non-hydro renewable. It is an absolute precursor to any significant amounts of renewable. The renewable portfolio standards in most states aren't worth anything because the grid cannot support double-digit levels of intermittent power sources without requiring absurd amounts of back-up power or storage. We need a grid that can handle intermittent renewables.

Question: Two things. First, there are companies like INEL out there that have installed or certified over 30 million smart meters in the EU, China, and Russia. It saves the company enormous transactional costs – reading, account management, etc. The cost at this scale is $100 per meter, about 1/3 the cost we hear about in smaller scale rollouts. The savings are as much as 25% of that amount each year. It's really good economic sense for the utility.

Second. How do we ensure that those smart meters use their intelligence? A VCR was already complex enough. If we start adding to your TV or computer a big screen with figures and graphs going up and down, telling you what is the cost of electricity at any given moment, I fear that a number of consumers might be overwhelmed.

Speaker: If a utility is short on generation and doesn't want to capitalize construction and expend lots of money, then this makes sense. In the U.S. many companies do not want to strand their investments.

Speaker 2: Many of the savings by Inel were operational savings, not on deferring generation. Further, their distribution system uses far fewer distribution transformers. Each transformer has many more houses.

Speaker 3: It's strange, on the one hand consumers get overwhelmed by too much information but on the other hand companies like to offer converged products. The synergies between ADT security and home energy management for instance. This has enormous value creation, similar to bundling cell phone, phone, internet, and cable services in one bill. You could add security services and energy management to that pot. At the US Consumer Electronics Show there were two hot items. Green products and integrated information displays on screens. Cisco has bought a company called Flip, and they are working on a first-generation touch panel television. Smart companies will design very sophisticated, but also very easy to use menus that allow anyone to create intelligent demand modeling for a wide variety of uses. Consumers will be able to "set it and forget it," they won't have to be constantly looking at real time prices, they'll set their preferences and maybe look them over 1 or 2 times per year.

Question: The meter must have a simple operation: metering in real time, and communicating in real time upon instruction. One can add sophisticated equipment and interfaces if you want.

One other thing that hasn't been emphasized. Smart meters allow metering in the other direction if there is a distributed generation source like an HEV battery, or solar.

Question: I thought I was finally going to figure out what people meant when they said smart grid. [LAUGHTER] I'm more confused than I was when I came in here. [LAUGHTER] I'm reminded of the Supreme Court who defined pornography as "I know it when I see it."

The fact that there are so many possibilities and the technology is changing so fast means we should be more focused on getting the bones right. Then the other third parties can figure out all the other fancy stuff. Today's agenda asks "are consumers sufficiently motivated and educated to take advantages of smart grid?" No they aren't because we have flat pricing that is too low at the peaks. We have to fix the pricing. We know that a time-of-use rate for every customer of 100 kW and above would be cost beneficial. This gets scale economies.

Deploy that as the first increment, that's a backbone. Why aren't we focusing on that first and not getting sucked into these subsidies? Beneficiaries and "who do we socialize" are real problems.

Speaker 4: Time differentiated pricing has to be layered over anything we're talking about here. We buy electricity every day, but have no idea how much money we've spent until we get a bill for a month that ended a week ago.[LAUGHTER]

Question: Electricity and water.

Speaker 4: Yes. I can't drink electricity. [LAUGHTER] Time differentiated pricing is an absolute necessity. I do think it is critical.

Comment: There is an issue with reluctance for the wires companies to invest in meters. They are concerned that revenue will go down. Second, we overlook customer education. It is absolutely critical. There may be customer reluctance and PUCs sometimes don't have the guts to implement these things.

The benefits our huge though. In Texas, the peak demand is 4-6 in the afternoon. It's a huge peak. They shave off some of that peak and customers save 15% off their bill, but ultimately the state's installed capacity goes down. It's a benefit to both the state and the customers.

Speaker 1: EPRI did a study this summer on behalf of four Ohio utilities to figure out what the societal benefits are. The operational savings only cover about 60% of the system investment. Either the consumers pay or it doesn't get done.

The four utilities that were independent in terms of what they thought smart grid was and whether they wanted to do it or not. All four were convinced that the study certified their position. [LAUGHTER]

This is going to occur jurisdiction by jurisdiction. That's the way we do things in this country. 5% of load in this country is already involved in demand response. There's no smart meter involved at all, a lot of people are just called up. This technology that we're trying to use has huge scale and scope economies. However, we can't selectively put in a mesh network radio communication to do one out of every three houses or one in ten. It's all or nothing. Parts of it are a big indivisibility problem. Ultimately it will be solved state by state.

Question: First, what are smart prices? I think they're oversimplified. Second, how to take and monetize the benefits? What are the highest value market triggers to get the smart grid to market? It's an optimization problem. Why not consider aggregated demand response for plug-in hybrids as an option contract, a bilateral contract? Why not use these resources at the time for the expected highest value payoff in a non-option contract format? This means you buy an option contract, you get that paid for in the market, but you're going to sell to this whole set of markets.

Speaker 1: One of the fallacies of a transaction economy is, how can you buy what you don't own? For ISOs, how can a customer who hasn't agreed to buy it sell it back to you or decide not to? ISO New England proposed a model that if you want to sell it, buy it. So buy a contract for a year, buy a contract for an hour if you want to trade for an hour. If you want to trade in five minutes, buy a contract with five-minute quantities, step up and trade.

Question: I want to think about the decoupling issue for a minute. You discussed favoring the straight fixed variable approach versus a balancing monthly reconciliation in Ohio. Why? Was that legislatively driven? How did they overcome obstacles to adopting that? This can be tough.

Speaker 4: They did not do it on the electric side. They did it on the gas side. It was not legislative. It was something the regulators thought was a good idea. They are getting pushback and it will probably end up in the Ohio Supreme Court. In the absence of a straight fixed variable, they can get to the point where they're actually over-conserving, if that makes sense. One shouldn't highlight that. It's just the logical thing to do. They don't have to have a true up every year or periodically.

Question: With the $4.5 billion that's been authorized for the smart grid pilots, what is the best thing that should be tested by companies that want to participate in these pilots?

Speaker 4: Well, it's a 50% matching grant.

Moderator: I would use what we call the micro grid concept. The idea is don't subdivide this thing down into bits and pieces which are self-canceling in value. Pick a community or a neighborhood and comprehensively transform the system on both sides of the meter in that particular community. Use that as a comprehensive demonstration to show the benefits and costs in an undeniable comprehensive way. Do it with all the stakeholders, the communities, the citizens. Get the private sector involved with funding so it's not just either state or federal funding. What we need is a complete, totally comprehensive demonstration.

With all due respect to our friends in the Department of Energy, they're very good in laying out demonstration money for things then nothing ever happens.

Speaker 3: There is the danger of reinventing the wheel. We have had many different studies on demand response, demonstrations, smart grid pilot projects. The San Diego Smart Grid Pilot Project was fabulous and the report on that gives a lot of great details. Nobody has really done a comprehensive soup-to-nuts demo with remote sensing, fault location and detection, smart transformers, intelligence in the substation, distribution management system, intelligent meter, intelligent end-use devices in the home, prices to people and their devices, dynamic pricing.

Speaker 2: Other's are taking a different view. GE's testimony in Congress had two points. First, money should only be allocated to programs where there are measurable benefits at the end. This could be efficiency, reliability, greenhouse reduction. The benefit should be quantifiable and measurable. Second, we need to see a project at scale. We need 100,000 units not 1,000 units.

Session Three.
Scarcity Pricing: A Good Idea With Bad Press?

Scarcity pricing in electricity markets is receiving renewed attention. Unpopular as always, the idea won't go away. With the completion of major reforms of capacity markets, such as in New England and PJM, attention can return to the undone task of improving market design for pricing in spot electricity markets. The FERC process under Order 719 is considering different frameworks. The Obama initiatives for energy efficiency, renewables, carbon pricing and so on would all benefit from better determination and transmission of prices signals. Arguably, these other initiatives cannot succeed without better scarcity pricing. Moving beyond the general principles of marginal cost, implementation of better scarcity pricing raises a number of conceptual and practical questions. What are the first principles for defining efficient scarcity pricing? How can locational features be incorporated? How can we integrate contingency constraints and probabilistic analysis? How do revenues flow in connection with capacity markets? How would scarcity pricing incorporate market power mitigation rules? What other market design features would be implicated with better, or just different, scarcity pricing structures?

Speaker 1.

Why it is that when it comes to natural gas we can have prices that go from $4-14, we can have gasoline prices that go all over the place but when it comes to electricity we have an expectation that prices will remain flat and constant? We have to address this question. This country has to be successful in a global economy, with 30 or 40% increases in electricity demand, and an 80% reduction in carbon.

First, I'll address the changing context: smart meters and rates, and price responsive demand. Second, I'll discuss how to integrate price responsive demand into RTO markets and system operations. Finally I'll discuss an operating reserve demand curve.

The industry has had a couple of assumptions. One is that demand was inelastic in the short run and second that therefore demand could not be used to set prices. We essentially assumed a vertical demand curve. These assumptions have produced a series of compromises. First, prices are set based on generator offers. Second, with a vertical demand curve and generator offers setting prices, prices could go through the roof and therefore we need a cap on prices. Once there was a cap on prices we needed a capacity market to deal with the missing money problem. There was also a potential for capacity prices to go through the roof so, in PJM at least, there are a set of administrative mechanisms that have mitigated virtually all of the capacity price offers. It's a market in which all of the buyers are required to participate and no sellers are willing to participate but the prices are ultimately set.

Here are the effects. First of all they take revenue and price signals out of the energy and ancillary service market. To create incentive for demand response to participate there's a need to have an intermediary curtailment service provider. It's a fiction that says that consumers have an entitlement to a certain amount of energy that they then sell back into the market when prices are high. These steps have created very limited scarcity pricing. In PJM scarcity pricing means that they eliminate in certain capacity emergencies the market mitigation that we put on generators, but they still keep the offer cap in place and have no opportunity for demand to set the price. This is not how an efficient market would work.

What if we change assumptions number one and two? What are the implications? Ohio is set to incorporate AMI metering and time differentiated pricing. The Wikipedia site on AMI has a link to a Google map that will show you all of the announcements of utilities around the world for advanced metering installations. It's more than 40 US electric distribution utilities in 37 states and the District of Columbia; 42 million AMI meters. The new stimulus package includes $4.5 billion of smart grid funding and they want 40 million AMI meters in American homes.

We often hear that consumers are afraid of the volatility of time differentiated and dynamic pricing. The answer to that is emerging in a number of places. These risks can be significantly mitigated through two part tariffs. Duke Energy has done this for the better part of the last decade. There is a certain quantity of energy purchased at a fixed price, increments above that quantity are priced at LMP. To the extent you reduce below that quantity you get a credit reflecting the market price. An analogy of that in the residential and small commercial market is critical peak rebates or peak time rebates. It's essentially a long hedge for these customers with the opportunity to sell that hedge back into the market at a market price when market prices are high.

This gives us price responsive demand. It is the subject of a recent paper by Paul Centolella and Andy Ott. It's different in important ways from the way we've thought about demand response before. Interruptible tariffs and water heater control programs are first generation, RTO demand response programs are second generation, this is third generation. It is based upon the predictable responses of customers to changes in wholesale prices because their retail rate design is responsive to the prices in the wholesale market. It is similar to every other market. The price of gasoline goes up, I consolidate my trips, the price of orange juice goes up, I drink milk in the morning. Something similar will happen when retail customers have an opportunity to see dynamic prices.

This is all dependent on making the business case and the investment in advanced metering to make this possible. Second, within RTOs these responses will not qualify as resources within the conventional resource adequacy framework. The RTO will not be dispatching the air conditioner in my home. The air conditioner will have settings that respond to the price signals in the advanced network.

A dynamic pricing tariff at the retail level has to be coordinated at the RTO level. There is a chicken and egg problem. The RTOs have resource adequacy requirements based on forecasting methodologies that don't consider price responsive demand. The forecasts are based upon time periods in which that demand response was not present. If we use resource adequacy requirements based on them it means people who have price responsive demand will be carrying resources and reserve at higher demand than actually will exist. Second, those capacity markets will build additional capacity which will dampen short term prices and spikes, and discourage significant demand response.

Some are concerned about reliability in this kind of system. However, folks from Reliability First are enthusiastic about this. Why? Because within the operations of the system this approach creates a beneficial feedback such that if a unit goes down or demand spikes unexpectedly, short term prices go up and price responsive demand goes down. It makes the system more stable, the power flows more predictable, the demand more predictable. It is arguably more reliable than the current system because it is responsive and adaptive.

This will bring more information into the system and helps harmonize reliability with the economic efficiency of the system. Let's examine some work from Midwest ISO. Prior to markets at MISO, when they called a level three or higher TLR, they were cutting transactions over the flow gate. The utilization of those flow gates over the next hour was zero. However, there was 12% unused capacity on those flow gates and more than 20% unused capacity on those flow gates in the next hour. Today their information systems and pricing allow for more than 99.5% utilization of the available capacity of the flow gates on the system. That's what information and pricing can bring you.

To summarize, there are five key elements to to integrate price responsive demand in RTO operations. One is the use of a transparent forecast demand response curve based on a statistically predictable relationship between price and demand. The entire curve should be transparent to have an opportunity to evaluate actual prices versus the normalized demand. This can improve performance over time and provide protection against under-forecasting. Second the range over which demand response can play should be expanded and an operating reserve demand curve is the appropriate way to do that. With the RPM market in PJM one has to synchronize the pricing of capacity with scarcity pricing. RPM pricing is based on the net cost of new entry. Scarcity pricing is deducted as part of the energy and ancillary service offset and developing that net CONE price. It's important that the scarcity pricing derived from the operating reserve demand curve be synchronized with that calculation so that people have a timely and effective way to hedge scarcity prices.

For resource adequacy it is important that price responsive loads both be required to have capacity with respect to their residual firm load and also that they have the option to hold additional capacity as a way to hedge price volatility if they choose. Finally, in a capacity emergency, any involuntary curtailments should be done on a nondiscriminatory basis. This would be based on the relative capacity deficiency of price responsive and non-price responsive loads which will require some additional tracking mechanisms.

Here are the key factors that regulators should consider. That they create markets in which demand response, including price responsive demand, can set prices. That is a market that is efficient, that offers the greatest opportunity for demand to mitigate market power and to enhance reliability. Second, that the market accurately reflect scarcity conditions in energy and ancillary service prices to provide the best price signals in a timely manner for good signals to demand response and generation. Third, that scarcity pricing is distinguished from market power. Generation market power should be mitigated where it exists while at the same time allowing prices to reflect actual scarcity conditions. Finally, remember the consumer and respect consumer preferences in terms of what provides value but also opportunities for them to see and hedge prices.

So what is an operating reserve demand curve? It assumes that we are maintaining minimum reserves required for reliability. The price at those minimum reserve levels would reflect the value of lost load to those customers who would otherwise be curtailed if we were not maintaining that minimum level of reserves. The RTO would obtain additional reserves as they're approaching a shortage. The overall effect of adding this operating reserve demand curve onto a demand curve that already reflects price responsive demand is that both of these have the complementary impacts of rotating and adding slope to the demand curve.

What are the effects of this on scarcity pricing? It shows prices in energy and ancillary service prices. This assumes that you have appropriate energy in ancillary service markets, that the pricing in those markets is appropriately co-optimized. It provides more accurate price signals to both demand response and to generation which should make the system more reliable.

Second, it sets operating reserves based upon the expected value of those operating reserves to consumers. The operating reserve prices reach an estimated value of lost load just before load would otherwise be curtailed. It recognizes the probabilistic value of additional reserve to consumers.

Third, it makes the system less volatile because it creates additional reserves before a shortage occurs, provides additional opportunities for people that need a little bit of time to respond. It provides market power mitigation, and lets consumers respond to prices or hedge.

They have to figure out how to do this on a locational basis both in terms of setting operating reserve requirements and forecasting price responsive demand. There are questions about how to define the local reserve requirements. There are some statistical methods which are discussed at a high level. There are activities between the Illinois and Ohio Commissions, Duke, and Ameren at MISO that are looking at the specifics of this.

Second, the value of lost load is something that can be difficult to estimate. The estimates vary within and between customer classes. Selecting an estimate of the value of lost load is in effect setting a shortage reference price. It should be done at a high enough level to be sufficient to elicit voluntary reductions at minimum reserve levels so that the risk of involuntary curtailment is minimized.

Both regulators and the industry need a path forward that is sustainable, reliable, and affordable as possible. Consumers have to be engaged. They need truth pricing and the ability to manage their bills and respond to the actual variants in the cost of providing them electricity over time.

Question: Price responsive demand is not just things that are under direct load control?

Speaker 1: No, it's the statistically predictable response of consumers to time differentiated and dynamic retail pricing.

Question: On the operating reserve demand curve, that's a service that generators are not being compensated for now?

Speaker 1: Yes. The current capacity mechanism is administrative and rough. The market capacity is longer on the resource side than if there were price responsive demand in the marketplace. There is compensation but it's not a very precise compensation that's going to generators. When an operating reserve demand curve comes there will be scarcity pricing not just in hours where there is absolute shortage but in a broader set of hours. That will tend to, if done appropriately, reduce the revenue stream in the capacity market but put it where there's much more accurate price signals.

Speaker 2.

There are operating reserve demand curves in the New York ISO, ISO New England, and MISO. This is distinct from the demand curves for the long term capacity market. They run at 15 minutes and they're already functioning. It is not a pie in the sky idea. It's simple to do, it's being done, and it can be included in a natural way in the dispatch. Part of what's missing is a theoretical framework for determining what it should look like.

While I can talk about the theory, I'm going to focus on implementation issues. One can derive an operating reserve demand curve if you ignore transmission constraints. Imagine a 15 minute period with some probability of outages or increases in demand. There may be curtailment, associated costs, and a value of lost load. Take the value of lost load times the probability of the curtailment and that's a probabilistic expected value of the implied price or the value of an increment of operating reserve. This can be integrated with all the various tariffs fairly easily.

Then you have to integrate the probabilities with the absolute minimums needed for contingency purposes so that you don't have cascading failures. That finally forms an operating reserve demand curve that can be integrated into the dispatch model.

Given these presumptions, let's consider the locational question because it's difficult. It's not that we don't know how to implement locational operating reserve demand curves. It is being done. They have locational operating reserve demand curves in New York, New England, and MISO. How do we think about locational demand curves? Is their structure consistent with generalized principles for a model that accounts consistently for location and economic efficiency?

So, in that 15 minute period something bad may happen, we may lose that line, we may have this plant go out. Demand may grow in a particular way, and then we'll have to reconfigure the use of the system. Some will happen automatically because of spinning reserves or transmissions limits will be implemented. The problem is for this probabilistic calculation as opposed to a normal dispatch one has to consider all the probabilities of all the things that might happen. It's an enormous math problem. The characteristic of the expected values story is that it smoothes out a lot of this story. The expected values don't have to follow Kirkoff's laws for example.

Trying to model this problem is virtually identical to long term planning of transmission. Lots of different scenarios and conditions with long term generation planning. As a formal mathematical problem they're the same. The numbers are different obviously because it's years as opposed to 15 minutes but the structure is the same. For the rest of this discussion, I'm going to discuss recent work by Bill Hogan on an operating demand curve with a locational component.

The transmission expansion process in PJM has dealt with this problem is to model a smoothing effect. It works because calculating expected values mean you don't have to describe the transmission constraints for each individual dispatch. The approximation identifies a constrained zone with a closed interface around it. Then they simulate the system for lots of different conditions to get an estimate of the secure transfer limit from outside the zone into the zone when we have to transfer a lot of resources over some short period of time.

The PJM terminology is the capacity emergency transfer limit, CETL. What's important here is the analogy to operating reserves. One can take the same structure, look at a zone identified through experience. There's a closed interface, meaning the maximum amount of capacity resources into the zone, and a requirement for operating reserves inside the zone. If that passes the laugh test as a reasonable approximation of the real problem then it is used to derive the operating reserve demand.

System operators and others have told me this is a reasonable approximation of what they do or it's what they actually do. [LAUGHTER] So it seems like it's a reasonable approximation.

For each zone in the system there's a dispatch with base load and generation. Deviations from that expected dispatch occur randomly over the next 15 minutes. That's the net load change Y; both outside and inside the zone. There's a closed interface limit going across and reserves on both sides; that's the setup.

This is a five dimensional problem. One has to calculate an approximation of the value of expected unserved energy. For every possible situation, given the reserves of each type and the interface limit, and the actual deviation of demand and generation capacity there's implicitly a problem to solve to choose the curtailments, the lost load, for both inside the zone and outside the zone. Three different equations model all the possible outcomes.

Block number one occurs if the net change in load and capacity inside and outside creates a large hit with curtailments inside the constrained zone. All the curtailments come from inside the constrained zone. In block two some of the curtailments go down to the minimum and the rest of it come out of curtailments for the rest of the system which is at a different and probably cheaper price. In block three the combination of net outages means all of the curtailments come from the rest of the system outside the zone. Those three regions are described by equations that account for all the possible outcomes.

So what is the valued of expected unserved energy? Well, what we really need to know is what's the change in the value of expected unserved energy if the reserves are changed a little bit? That's the demand curve. Those three block equations provide the answer to that question. The amount that one would be willing to pay in order to get one more unit of operating reserves inside the constrained zone is equal to the value of lost load in the constrained zone times the probability that I'm in region one or two.

One can do the same calculation for the reserves outside the constrained zone and the interface capacity. There's value to increased interface capacity, how much is one willing to pay for that? It has to be represented in order to get a correct representation of what the total value of all these different reserves. Once this is all accounted for, one can solve for these prices as a function of the basic probability distributions and as a function of the values of lost load.

Several characteristics emerge from this exercise. First, there's an interaction between demand curves, they're interdependent. The dependence is not nested or cascading. In New York they assume that there's a demand curve for price in reserves that's additive to the demand curve for the price in the rest of the state. It's not the right way to characterize the problem.

Second, convergence. As the interface capacity increases the price in a constrained region and the unconstrained region goes up till you get all the way to the completely unconstrained case. The interface demand has a price that has to be represented in the model.

If we apply this approach to the sample New York data you end up with a demand curve at a high price that doesn't go all the way to $10,000. The high intercepts are around $6,300 inside the zone and $3,500 outside and they both trail off, but don't go to zero. In essence, the demand curves are sensible and they have all the kind of properties that one would think they should have and they're a little bit different than the ones currently being used.

One can extend this idea to multiple zones. The equations can be extended for another zone. It just gets to be a more complicated array of probabilities that have to do with the different conditions of which interface constraint is binding under which conditions. Sometimes one, sometimes neither, sometimes the other, sometimes both, and that affects all of these numbers. One can nest them or add contingencies as well.

Suppose we use this operating reserve demand curve? It's a necessary missing piece from market designs for all sorts of missing money and first principles concerns. It solves the chicken and egg effect in terms of getting the price responsive demand. A price signal has to be sent to set price responsive demand. The interesting question is, what will the frequency of operating reserves be over different kinds of conditions? Some people see the very high prices and say that is politically unpalatable but those prices will occur very very little. Most of the time the price will be much less. So what's the distribution associated with those prices? I didn't know the answer so I made it up [LAUGHTER] just to illustrate the story.

What I did here was draw three hypothetical curves and one real one. The first hypothetical is the latest number from PJM about the annual capital charge for a peaker that has to be made each year through scarcity pricing. That's $75,000 per megawatt year. If it's averaged across the whole 8,760 hours per year it's a small but consistent fee. That's what the capacity market is doing but it's not charged to the customers at the time that it actually hits so they get a real in-time signal. It's just spread out over the whole year but a real time price signal is completely muddied.

Two other hypothetical curves can show frequency distribution of prices under the model I've just discussed. One could have a higher frequency of lower prices and the other lower frequencies but then very high prices. They both have the characteristic that they add up to the same total dollars over the course of the year. One can compare these prices to the real price for ten minute spinning reserves in 2008 hour by hour in New England. The area under that curve turns out to be $14,681 per megawatt year. The difference between the $14,681 and the $75,000 is the missing money. That's the money that the RTOs are trying to make up in the capacity market. It is an enormous difference. Boy, we have a long way to go here in making this up. The locational operating reserve demand curve could go a long way in helping that, and unlike the capacity markets, would do it showing real time prices to the markets. I'm not sure it's going to solve that problem but it will make a big difference. What we don't know yet, is what's the real duration curve look like if one actually implemented operating reserve demand curves that had these material prices, that were extended over the whole range, and that weren't truncated.

The real ones that function in the RTO markets are truncated, they're not extended over the whole range, they don't go up to the very high prices at the low levels. They're underestimating what the scarcity value is. If the zonal value of expected unserved energy was calculated properly it could be incorporated in a natural way in the dispatch.

This approach is a simple model which is an approximation of what we think the operators are doing anyway. It doesn't try to change what the operators do. Instead, it's a reasonable approximation of what they're doing and then characterizing the prices. The approach would have a very high leverage effect on many other things. It affects prices for energy, for reserves, for capacity market payments, and the transmission congestion differentials. It would permeate the whole system. Everyone says that we're putting Band-Aids on all the problems out there and we're going to deal with this later. Now is later. It's time to deal with this now.

Question: This is conceptually elegant. I'm concerned about reserves of different types: ten minute, 30 minute spinning, non-spinning, and then energy itself. Isn't there the possibility that you could have constraints of reserves of one area, say the 30 minute spinning, that are not in the ten minute or in the energy market? How would you nest these issues where there is scarcity in one pocket but not in the others? The pricing would then be sort of unusual. There would be lumpy binary assets that aren't smooth so you might have no plants that are available for one specific type but you have it of others. We've seen that in the ISOs in some cases.

Speaker 2: I don't think there will be pricing differentials. If you implement it correctly then nesting will take care of it. I would be worried about the operating sense after the fact; different sources being constrained in different time frames. Consider the start of the hour and the pricing is based on the dispatch then and reserves are priced on the expected value of the next 30 minutes. Assume we have ten minute and 30 minute reserves but in both cases it's the expected value at the start of the hour, not what's going to happen. One could have a completely different zonal description for the 30 minute than the ten minute. That would be perfectly fine. It would affect the individual plants but it wouldn't affect this basic model. The ramping issues are a question but they could be worked out. It is not an insurmountable problem.

Question: Can you run the same type of algorithms for the day ahead market as the real time in this case?

Speaker 2: Yes.

Speaker 3.

I'm going to discuss the Cal ISO scarcity pricing design. They are the newcomers in terms of scarcity pricing. After MRTU, their new market system, is implemented they will have final stakeholder discussions to improve their design. In the 2000 order, FERC directed the Cal ISO to design and implement a reserve shortage scarcity pricing mechanism within 12 months after MRTU implementation. FERC specified features which price automatically during the period of the reserve shortage and administratively determined prices to various levels of a shortage, in both day ahead and real time markets.

It will be a demand curve approach scarcity pricing like New York, New England, and the MISO. The minimum reserve requirements are based on the NERC and the WCC reliability criteria which generally have to be met at any cost. However the market can't clear at any cost. Scarcity pricing is an administratively determined price that both the ISO and the stakeholder agreed upon, and the approach is transparent. There's no need to guess when a shortage will happen and what the prices would be.

Finally, the reserve substitution rules mean that a higher quality reserve can be procured to meet the requirement for lower quality reserve. At Cal ISO the regulation reserve is divided. Regulation up is the highest quality reserve. It can be used for spinning and non-spinning. Also WCC and the NERC reliability criteria specified the minimum reserve procurement requirement for the Cal ISO system, that's regulation down. Minimum procurement targets for sub regions based on the system condition and reliability considerations may require higher quality reserves. Reserves procured in the sub region also count toward the requirement for the whole system.

The price of higher quality reserve in sub regions is always higher than or equal to the price of lower quality reserve. The value of the demand curves are set based on whether the shortage is transitory or persistent, or whether the shortage is local or system wide. If the shortage happens only in spinning or regulation it's most likely a transitory shortage caused by lack of ramping capacity, not by lack of capacity. There are resources still available at a certain cost and the resource might not be economic before scarcity pricing is triggered. Once the scarcity price is triggered and the price goes up. those resources become economic and provide additional supply for spinning or regulation and they relieve the shortage.

However, if a shortage happens in non-spinning, it may be persistent because it's most likely caused by a lack of capacity. The price there needs to be high enough in order to trigger a resource such as a demand response. The prices are additive. So if the shortage happens in both spinning and non-spinning the price for spinning could get as high as $800 per megawatt hour. In the worst case there is a shortage in all the reserves, system wide and the sub region. Then the price can get as high as $1,000 system wide and $1,450 in the sub region.

This sets the price properly to reflect the value of a short resource. These prices are high enough to trigger demand response resources. They have two types of demand response. One provides load reduction and the can provide both energy and a reserve.

California also has a resource adequacy capacity program. Serving entities are required to procure capacity up to 115% of their peak load. However, those capacities are not required as reserve. Thus scarcity pricing rewards capacity that is capable of providing reserve.

A big concern is market power, so market power mitigation is an important aspect of the scarcity pricing design. Cal ISO will procure 100% of ancillary service in the day ahead market. The ISO will require capacity to provide both energy and ancillary service in the day ahead market up to the maximum capacity for ancillary service. They can prevent capacity withholding and artificial scarcity. Once scarcity price is triggered the demand curve approach scarcity pricing mechanism will set the price based on the level of shortage.

Speaker 4.

I'm going to discuss scarcity pricing in PJM, and their consideration of a move to an operating reserve demand curve. They have scarcity pricing, it's just not complete. They are largely for spinning reserve although sometimes a primary reserve perspective may be used which would be spin plus non-spin in real time.

The scarcity pricing regions are defined on the Web. When they are entering into a shortage condition they announce it but it's often not clear ahead of time. Scarcity pricing triggers based on loading physical equipment, not on the actual amount of reserves. There are generators and load response in PJM that can only be dispatched during a capacity emergency. Some have environmental limitations, some are just very old but they're obligated to respond during a capacity emergency.

Scarcity pricing is not triggered until PJM actually loads emergency equipment. The triggers are based on a fairly severe operating condition. Scarcity price gets set based on the highest price offer of any unit running whether it be emergency or economic. They remove price offer caps for local market power, so they remove market power mitigation. PJM only has local market power mitigation in any case, there's no system wide market power mitigation. Once scarcity price shows up it's amazing how resources appear, both generation and demand response. Unfortunately, it's not predictable at this point. They can lower a generator if there's too much in an area and a transmission constraint is created. The overall offer cap of $1,000 remains.

There is overlapping scarcity, the scarcity pricing regions are not nicely nested. It's similar to the way the capacity market is designed. It does create an interesting optimization problem but very solvable. There's product substitution between them.

The preparation of the emergency operating region starts with loading long term emergency demand response. It has to be called four hours in advance but it reduces the need to dispatch economic generation. At that point the price will fall when everybody knows it should be rising. They load emergency generation that has a lead time and on a hot day it will start at ten am. This is the beginning of extreme price volatility. The prices dip around between ten and 11 and they go a little crazy at noon and then they start to go up as one would expect them to go up. Those hitches create immense uncertainty in the market. The folks who are responding to the price signals are sitting there wondering why when they see load continuing to grow, but the price is going down. It's an issue. The price doesn't necessarily need to get higher, it needs to get more predictable. An operating reserve demand curve will stabilize that.

The fact that a shortage isn't signaled in advance is also a problem. It doesn't give entities who would respond to the shortage any advance warning today. No one can plan ahead.

Principles for scarcity pricing, should equal the marginal willingness to pay. However, that's less important than to say that the pricing needs to be more predictable. I think that is the issue. An operating reserve demand curve will create predictability. Putting in an operating demand curve doesn't mean prices necessarily rise during other times. It means prices will stabilize as an emergency begins.

An operating reserve demand curve means that market power mitigation does not have to be suspended. The demand curve will set the appropriate price. What about the different types of reserve? There is unsynchronized 30 minute, unsynchronized ten minute, and spinning reserve. There is product substitution among those. The lower quality can be satisfied by the higher quality reserve if necessary.

What about principles for implementing the curve? One has to synchronize the scarcity pricing curve with the reserve levels. It also has to be synchronized with the retail rate design for price responsive demand. That's extremely important if you're going to incent demand to participate in this market. That has to be done up front. Pricing has to be transparent.

PJM already accounts for the locational aspect. However, it needs to be articulated better and implemented more completely. The design of the capacity markets needs to account for an operating reserve demand curve.

The curve does goes asymptotic and gets down to the zero point. It is not often expensive, the number is six cents in PJM in those regions where they have plenty of reserve. It's a low cost for reserves but much much higher in shortage conditions. Total energy prices, in my opinion, shouldn't go up a lot under this mode. One doesn't need to increase the $1,000 price cap on generation because the operating reserve demand curve will reflect that itself. It's very similar to the capacity market; the expectation is everyone will put in their avoided cost for the capacity market offers as opposed to some other number.

Question: What are the characteristics of generators and demand response [DR] over multiple hot days?

Speaker 4: It varies by condition. If it's the first hot day you might get as much as 5% more DR than you thought. If it's the third or fourth hot day it's less. The generators have different operating characteristics, the demand response has more ability to come in early. As the heat wave continues DR gets fed up, if you will. It's not predictable right now.

Question: How does one get LOLE [Loss of Load Expected] determined with some veracity at the local level? Or VOLL so people can actually agree with that? California, may differentiate VOLL based on customer groups. Residential would obviously be very different. That starts to become controversial. How do you make this simple? How to make this politically palatable for less sophisticated commissioners?

Speaker 1: First, the RTOs and planning reserve sharing groups do LOLE calculations today. Some is fairly sophisticated and done on a regional basis. I'm not sure that the LOLE calculation per se is as problematic as you suggest. VOLL will be more controversial. The Lawrence Berkeley National Lab had a paper where they examined the value of lost load studies and built a meta model for estimating value of lost load given the specific kinds of customer parameters that were in any given area. There are differences both within and between customer classes when you play that out. The median VOLL for residential customers was around $1,500 a megawatt hour. This is looking at a one hour reduction in summer peak. If you talk about a two or a three hour reduction the marginal cost of that second and third hour tends to be less than the first hour. Overall, 95% or more of residential customers had a VOLL of $2,500 a megawatt hour or less.

Those are based on surveys of actual customers asking them what is their willingness to pay to avoid an outage on summer peak.

With commercial and industrial classes one can attempt to calculate their actual outage costs associated with an interruption in terms of lost production, in terms of materials that are ruined, in terms of labor cost that is unproductive, etc. The VOLL numbers tend to be higher there. Depending on what type of customer you're talking about, anywhere from $12,000 - 40,000 per megawatt hour. There's variation within customer segments in C&I as well as between. One has to address what is theoretically correct and also what is going to be acceptable. What types of customers would be curtailed in the absence of meeting those minimum reserve requirements?

Some Commissions have looked at curtailment priorities in a very detailed way. Ultimately, it's a political judgment call within the RTO about what is the appropriate reference price for involuntary curtailment. There are different perspectives on this and the answer may differ from RTO to RTO and it may not coincide with the theoretical appropriate answer.

There are two important parts of the discussion with a regulator. First, what we do with capacity markets has large degree of regulatory judgment that is not closely tied to getting price signals right. There's a fair amount of dissatisfaction among regulators with capacity markets. This gets prices much closer to being right by reflecting the actual conditions as the market operates. Regulators can understand that.

Second, it's important to emphasize the fact that these prices have a dynamic element at the retail level. A retail framework can provide small commercial and residential customers a significant forward hedge and the opportunity to experience the benefits of having some elements of dynamic pricing. Alternately one could start with something like a peak time rebate tariff. Over time customers would recognize that there are competitive offers that include a smaller hedging premium but still some hedge so that their bill doesn't necessarily go up all that much even when prices rise.

Customers can control their exposure to those high shortage prices. They can be price responsive, or they can hedge depending on their capabilities. We may see more dynamic retail competition in that kind of a model.

Speaker 2: One concern. Suppose there are multiple categories of people that are going to be involuntarily curtailed. Are commercials going to go last because they're more expensive? What's the appropriate thing to do? It complicates calculating the value of expected unserved energy. It doesn't complicate the price for the demand curve because the only thing you're interested in on the price demand curve is the marginal effect and the marginal effect is defined by the first group which you have to interrupt. However, the first group sets that value.

Question: How will PJM set the interface between the operating reserve demand and retail pricing. How does the synchronization work? Second, you said they won't necessarily need to change the $1,000 price cap. I was assuming that the operating reserve demand curve would set the market price even if it got to $3,500. How is that not increasing the cap?

Speaker 4: I misspoke. I meant offer cap. If I said price cap it was the offer cap for the generators. PJM doesn't have a $1,000 price cap. The $1,000 is an offer cap from the generators.

On the first question. An operating reserve demand curve will stabilize price performance as they enter into shortage. The synchronization that needs to occur is the price responsive demand, meaning the demand that would respond and get off the system. It's a process of signing up to be price responsive under a retail rate. From the RTO perspective it would not be getting a capacity requirement because it's going to be gone before the RTO is in a shortage condition. Again, that's an assumption and obviously it would be at some point curtailable if it didn't get off in response to price before the RTO gets to an emergency condition.

The retail rate design has to be incorporated into the demand curve. Say there's critical peak pricing where at some point the wholesale price is high enough for a customer to reduce; they either get the rebate or they start to see real time price. That has to be synchronized with the pricing operating reserve demand curve because that price has to occur before the RTO goes into shortage. That's the synchronization, they have to actually work together or else it would be ineffective.

Question: So if they're posting a price of 2,000 and wanted a retailer to offer a price higher than that or lower than that, that those numbers need to be, synchronized, the same?

Speaker 4: The retail rate design, depending on the type of retail rate design, would be passed through to the customer or would give a rebate to the customer if the wholesale price went above a certain amount. That trigger point has to be below the point at which the RTO would be in emergency as defined along the operating reserve demand curve. They have to get that load off before we get into emergency. So the retail rate design for that trigger point has to be synchronized at or below where the RTO scarcity pricing design is.

Question: It's not the price itself that you were talking about?

Speaker 4: It's the trigger. It depends on the retail rate design. Some retail rate designs may be that way already, others may just be real time price all the time, but the RTO has to accommodate them all.

Speaker 1: That's right. If the RTO ultimately gets to the emergency, the curtailment has to be done in a non-discriminatory way. It has to be done based upon relative capacity deficiency so that if there's a price responsive load that just hasn't responded - it may have some capacity that it's holding, or additional capacity that it's bought just as an additional price hedge – it may respond.

Speaker 4: Right. If it's not covered with capacity it has to go, the portion that's covered with capacity doesn't have to go of course, unless the RTO is into network load shedding for instance.

Question: First, how is the two part tariff retail structure structured? If it's a fixed rate for everyone some people would see it as a great deal and others would see it as a terrible deal based on their actual expectation of usage, right?

Second, are these one size fits all so the same percentage applies to everybody? Or do customers get to choose how much they can fix under these retail plans? Because it's problematic if people can pick off this fixed rate that's uniform and they're actually going to be using mostly on peak. Nobody would ever take it if they're using mostly off peak.

Speaker 1: The most sophisticated version is a two part real time pricing tariff. Duke has had it for a number of years, Georgia Power, even though it's not in a market, has had a two part RTP for its large industrial customers for 20 years. There is a fixed load profile that is purchased at a fixed price. If you use more than that amount of load you pay the LMP or in Georgia Power's case their system lambda for that additional consumption. If you use less you get a credit for the difference between LMP and the amount that you had purchased at the fixed price.

For residential customers it would be a critical peak rebate tariff. It is similar to the two part RTP except that the forward hedge is at a very high level so that in effect they never have to worry about paying incremental over and above their fixed quantity. The fixed quantity that's purchased forward for them is plentiful but to the extent they have an opportunity to sell some of that fixed quantity back into the market they get a credit for the difference between that fixed price and the LMP.

So how does that play out in terms of the large industrials? There may be some contract negotiation that goes into figuring out exactly what the quantity is that they're purchasing forward. It's usually a kind of collective assumption that the hedge will be set high enough that nobody has to worry paying the incremental cost. There's a hedging premium associated with that. I expect some smaller customers will move to other types of rates that don't have so much of a hedging premium built in.

Some people will be natural winners even if they do nothing. Their usage is less peak oriented than other customers. Generally, lower income customers tend to be less peak oriented than higher income residential customers. Most flat rates actually have a regressive component in that people who don't have big houses with two or three central air conditioners are actually subsidizing higher income consumers because of flat pricing. Most low income consumers will be automatic winners, around 95%. That's attractive to regulators.

Question: I like this new idea because the smooth process that can exist in the day ahead and real time markets is actually critical. However, does the implementation of scarcity pricing exacerbate seams issues between markets?

Speaker 4: I don't know that it exacerbates the seams issues. I think most of the markets as they approach shortage conditions have certain protocols about how shortage is handled. Meaning if something is not a transaction between regions it is not capacity backed, it'll get shed first. There is a fundamental consistency between what happens within a region as far as curtailment and what happens between regions.

The next question is what's the price performance as you approach scarcity? If one region has an operating reserve demand curve and the other one doesn't, their neighbor's price volatility will be a problem. Nonetheless, there are issues with price convergence already across the seams so I'm not sure this creates more.

Speaker 2: Well if one region adopts scarcity pricing and the other doesn't the one that adopts scarcity pricing is going to suck everything in from everybody else.

Speaker 4: Exactly.

Speaker 2: So it's a good defensive mechanism to adopt it yourself. [LAUGHTER]

Speaker 4: Well, if it sucks too much and the other one's in a reserve shortage the protocols will cut it off in any case. There are agreements in place to stop it.

Question: I'm worried about power marketers ability to successfully transact even with good price signals. Because operating procedures all of a sudden start getting in the way and they're non-price sensitive. There are price differentials across seams but no transactions to address them.

Speaker: If there's an operating reserve demand curve in place it should reduce the amount of times there are emergencies. It will empower power marketers.

Question: In the locational model can the interface function as its own constrained entity for scarcity itself? That could also be a way to have two scarcity models, one from each market, sharing that same scarcity at the interface. It would converge the seam problem.

Speaker: The scarcity at the interface is not transmission limitation. It's really availability of resource.

Question: Scarcity price payments provide some missing money that's otherwise coming from capacity markets. They are a structure that is self correcting because they are reducing the amount of money that's being paid out through the capacity market structure. Is that correct? What happens with scarcity pricing in a place without a capacity market, like California's bilateral structure for resource adequacy? Can it work?

Speaker: Yes, bilateral contract prices will self correct it. The reason you need to administratively come back and adjust the reference price for the capacity is because you've administratively set that price and there is a certain assumption about energy revenue. Now one has to go back and fix that assumption. If it's bilateral contracts there will be winners and losers. They're essentially determining those prices on a forward basis and those will adapt on their own because there's no price administration on those.

Speaker: I think so also. I'm not all that familiar with the California market but I would expect folks to hedge forward by some combination of energy and capacity. If not then folks see the scarcity price.

Question: California is trying to put in a capacity market. So, those that are negotiating bilaterally for resource adequacy contracts should over time build in the expectation of the revenue that they might expect to see from scarcity pricing. It'll be reflected ultimately in those prices. It sounds less efficient and smooth than places with capacity markets.

Speaker 4: I don't know about that. A forward energy curve is dramatically impacted, at least in PJM, by price performance during shortage. At a hot summer day and the change in the forwards for energy go up a lot. They're saying OK, there they go again. You know, either they got it right or they didn't. An operating reserve demand curve will stabilize those forward curves. There's a lot of other reasons for capacity markets, tracking responsibility, things like this, but that's another issue.

Question: There is value in trying to achieve a price signal associated with scarcity pricing. However, it should interact appropriately with whatever the resource adequacy mechanism is. California's situation may be problematic.

Speaker 3: The market would reflect the negotiation of the bilateral contract. Further, if the resource adequacy program goes to the locational it reduces the chance of triggering scarcity pricing. It identifies a local area that has higher requirement for the capacity. It would provide incentive for additional resources built into this local area.

Speaker 2: The one concern in all this is if you sign a contract today based on an assumption about how scarcity is going to occur in the future and then we change the rules and you're still stuck with the contract. With seller's choice contracts in the past, folks from PJM would go around and have classes, saying, "don't sign these contracts!" When LMP was implemented those folks would get clobbered.

Question: How does non-discriminatory involuntary load shedding work? There's a switch inside someone's house? Load will get cut specifically?

For these folks who have the lower non-capacity rate what if they change their mind? It's hard for regulators to say no but they are creating a burden.

Speaker 1: There are many potential answers to those questions. There are metering options that can have a demand limit on them. Inel's advance metering, for example, all of their retail contracts are demand limited contracts. If one goes over it for more than 30 minutes the service shuts off. It will depend in part on the competitive contract. Some devices will be turned off remotely. It will also depend on the available technology, and also on the regulatory framework.

Consider an LSE with some price responsive customers and a certain amount of capacity that it is required to buy and other capacity it may have voluntary bought as a price hedge. The objective should be to be as non-discriminatory for that LSE versus other LSEs that may be in a different capacity situation relative to their peak demand at that point in time.

Second, at what price do people get to come back once they've gone to a competitive offering? Regulators answer that question in a wide variety of ways. Differently in different states, and sometimes in different cases in the same state, and certainly for different types of customers. In Ohio if you're a large enough customer you have a choice. There's many variations. For smaller customers there's more of a debate about whether or not they should have the option to leave and come back at a market price and not pay a standby charge.

Question: What is the optimal size for the zones in the locational model?

Speaker 2: Some sizes are better than others. It interacts very strongly with the assumptions used for the interface limit. The CETL calculations for long term planning use a one in 25 year reliability standard. They have not done optimization of that for size. However, it affects the configuration of the transmission grid is. So there are differences but I haven't given much thought about how to optimize it.

Speaker: The transmission system configuration will drive the optimal definition. Sometimes it's old utility boundaries. Eastern Mac and Southwest Mac zones were based on engineering analysis of the reserve characteristic in that region and the transmission. That's a good way to go.

Question: The engineered zones tend to be larger than the historical ones.

Speaker: Yes, they tend to be more regional. My guess would be they'd be combinations of several utility transmission zones.

Question: Can the scarcity pricing construct be applied in markets without a competitive wholesale market and structure?

Speaker 2: Well, one is trying to do economic dispatch and there is varying value associated with the operating reserves. So you get that benefit even without a market. It helps with economic dispatch, the right level of reserves, the choices of energy, the transfer limit and all these other kind of things. It's still useful.

Speaker 1: The one complication is that a regulated vertically integrated utility has revenue requirements based upon their embedded costs. It almost becomes like the two part tariff in the sense that there is some kind of historical entitlement to a price based on embedded costs. However, you want the marginal increments from some baseline priced at system lambda. That has to be addressed.

Question: Incrementalism is important because customers need to get used to peak period pricing, scarcity pricing. So do utility planners. What are the components for a program? Good information, pricing, and communication. And what about retail competition? And what about the different segments: C&I, and residential. How do we implement all of this? Can it be done incrementally?

Speaker 1: Retail competition is dumbed down for the most part. As it gets more sophisticated it will allow for more dynamic pricing options. Competitors are waiting and hoping for more refined models.

I think residential customers get a peak time rebate tariff as POLR tariff. Then a competitive supplier can help some manage that risk, or allow for more exposure to real time price.

For C&I, they're largely differences in sophistication. A large industrial user will have employees devoted to these energy issues. Medium level commercials can work with a company like Comverge.

Question: Should we extend scarcity pricing to retail pricing in non capacity market markets? A two part tariff is one obvious way to integrate it. Is there another way to do it? Can we do it? What about a place like MISO without capacity markets?

Speaker 1: They have capacity markets.

Question: For ancillary services.

Question: There's an installed capacity market in MISO as well, module E.

Speaker: It's not an organized capacity market.

Speaker 4: It's not a long term capacity market but it can have an operating reserve demand curve and scarcity pricing. There's just no administrative tie back to the energy revenue in the scarcity linked to the capacity market. Forward bilaterals and other contracts will certainly respond. There will be winners and losers, hopefully not because of stupidity but just because it happens. An operating reserve demand curve will be very helpful.

Question: What about the political constraint of putting scarcity pricing into retail pricing. Is that going to be palatable?

Speaker: No.

Speaker 4: It would require a lot of articulation; very hard. Even when revenues will shift from capacity to energy. It will be difficult anywhere.

Speaker 1: MISO has regulators across the region who are sympathetic and favorable to price responsive demand. Some states there are ready to move forward.

Question: One can't lost the fundamental faith in the consumer. They'll respond to prices. Same as people who sold their SUVs at $4 per gallon gas. Ultimately consumers will be enormously empowered.

However, the retail consumer has not been a participant in the deregulation of the utility industry. It was great for industrials, but residentials are still at standard offer. Given the various complications, is an incremental approach correct?

Speaker 4: I think first put in operating demand curves. If scarcity pricing and price responsive demand doesn't effectively come back and benefit the consumer then it won't occur. Environmental constraints with renewables and carbon are going to change the equation a great deal in any case. It's exactly the right time to pair it up with scarcity prices. We need that kind of demand response.

Speaker 1: This approach gets us to where we need to be in ten years. However, it also creates openness in the system, and an atmosphere for innovation for the longer term. That will help with the environmental challenges also.

It will also help operators in some ways. They will gain beneficial feedback effect on their information and a reduction in terms of price spikes and mitigated outages. We need to proceed carefully but ultimately putting all of the things that we've talked this morning in place as a package is right, and operators can handle it.

We need more social science research on how customers are going to respond, not just to price signals but also to enabling technology, to things like programmable communicating thermostats, home displays, or billing messages.

Question: A comment on scarcity pricing and retail rates. It won't be a hard sell if they're well hedged. It'll be a very small effect on rates. Or is the real problem from public power buyers?

Speaker 2: Well, on average the higher prices you pay for energy are compensated by reduced prices in capacity markets. If they're hedged, that reduces the volatility, and there shouldn't be price hikes.

Speaker: Yes, the key problem is explaining it to advocates who show up at stakeholder meetings. They need to understand that it's cost-shifting towards better price signals, but not cost-increasing overall.

Speaker: There is always fear of the unknown, it's change. One has to articulate what the change means, and get them to understand that it is a zero sum game if you have an increase in energy price in an area but a decrease in capacity market price.