

**Harvard Electricity Policy Group
Thirty-Fourth Plenary Session**

San Diego (Del Mar), California
March 1-2, 2004

RAPPORTEUR'S SUMMARY*

Session One: Reliability and Markets

Reliability is a public problem. While individual market participants can control the reliability of their electricity supply to some extent, strong interactions in the grid make reliability decisions a collective challenge. Operating and commercial rules interact to affect reliability. Markets emphasize decentralized choices and indirect interactions to achieve good outcomes in the aggregate through individual pursuit of self-interest. With the right rules and incentives, markets could reinforce reliability. But with flawed rules or bad incentives, reliability and commerce could be at war. The aftermath of the Northeast blackout illustrated once again the importance of reliability. To what extent is the lesson that markets and reliability can coexist, or must markets be short circuited to preserve system integrity? Are the present institutions capable of managing the transition? Do we know where we are going? What policy agenda flows from the recent experience?

Speaker One

My premise is that we still have the most reliable transmission, distribution and generation system in the world. Perhaps we can debate that, but I do not think any events have transpired to change that. However, the grid is being used today in ways for which it was not designed, making it more vulnerable to reliability problems. To make improvements, I think we need to acknowledge the current limitations and recognize the need to maintain a focus on native load customer reliability.

My company has about 13,000 MW of capacity and about 20,000 MW of POLR obligations to customers. We rely on the market every day, but we cannot change the fact that hundreds of thousands of miles of transmission lines were designed and built for entirely different reasons. We cannot continue trying to make the system what it is not.

The current reliability standards do not address changes that have come with competitive markets. New plants based on opportunity are locating near existing transmission lines or existing fuel sources, but far from the load centers they intend to

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serve. New, single-unit control areas are being created to avoid any requirement to support the grid. But all generators must be required to support the grid and take action to maintain reliability. Ultimately, the margins on the transmission system must be replaced as they were in the past.

We need to better understand the grid's vulnerability to long-distance power transfers and new power plant hookups, and the consequences. We need to provide operators with better tools and technology, including more access to more real-time information. Our RTOs must be organized in ways that enable them to provide the means to evaluate availability, performance and encourage investment. They must be required to communicate with neighboring systems when they take actions that could affect others. Most important, electrically significant systems must be under the same reliability authority. If that is not possible, then robust agreements for inter-RTO coordination must be in place. However, if we rely on the latter, we must recognize that these paper obligations will be inadequate in the long term.

Reactive power must be examined within the context of operating efficiency in transmission. There must be sufficient supplies of this and other ancillary services, and again, all generators must be required to support these. Another needed reform is a better means of scheduling power region to region. We can no longer ignore the burdens of unscheduled power flows that occur by relying solely on the contract path model for long-distance transfers.

Although we have more users, we have not created any incentives for grid investment. Maybe we need to reform the governance structures of the RTOs if we cannot figure out another way to encourage investment. Right now, there are far too many areas of the country that are no longer providing the local

generation resources necessary to meet their requirements. We need to think about how our regulatory system could clarify its goals so that investors can receive assurance that they will get recovery.

There are no quick fixes to the challenges our industry faces. But the best chance of overcoming them hinges on putting customers and reliability first. Whether that translates into more opportunities for customer savings, is not as important as providing them with quality and reliable service.

Question: If paper obligations would not be adequate for electrically significant systems that are not in the same RTO, what would be adequate in the long term?

Response: They may not be adequate in the long term, and they probably will not be. We need to figure out what that means and how we will operate when you put it on paper.

Question: How did we get investment in the past? What is different today?

Response: Transmission was built primarily to move power from a plant to a local utility service area and interconnections were put around that. The issue is whether we are building enough transmission to accommodate long distance power transfers. For example, how do you design a line in Ohio that will move power from Indiana to New York, when there is absolutely no need for it in Ohio? That investment must be made if we want to use the existing system to accommodate these transactions on a more day-to-day basis.

Speaker Two

The interim report issued by the US-Canada Task Force in October 2003 was extremely well done and clearly written. I expect the final report will be, also.

Subsequent benchmarking and adjustments to the models will show that they were closer to the reactive limits on August 14 than earlier studies indicated. Instability occurred a bit earlier than the October report indicates.

Positive outcomes of the study effort include the joint involvement of organizations like NERC, FERC, DOE and others. They were able to work together and support each other and that helped make the investigation a robust effort. The weakness of the voluntary model is evident, as is the need for stronger enforcement mechanisms.

Another positive outcome is that if national energy legislation fails, FERC is looking for alternatives. It has talked about possible tariff-based solutions, or even using good utility practices to invoke the necessary authority. The commission is working in tandem with NERC. Around the country, situational awareness tools run the gamut from highly sophisticated technology to very unsophisticated manual efforts. I think stronger standards will emerge for the “three T’s” of tools, training and trees, or vegetation management.

The August 14 blackout has produced a few myths. One is that there is too little transmission. My own view is that part of the problem is that there are too few large, regional markets with security-constrained dispatch. Another myth says that deregulation caused the blackout. I say the truth is that poor execution in the three T’s is more the cause. People also say that the scope of control is not an issue or is unimportant. I maintain that we have too many small control areas. It made sense when vertically integrated utilities were serving their own load with their own generation, but today having 140 control areas no longer makes sense when we have transactions across multiple control areas. The communications problems that existed on August 14 and that still exist

across boundaries are reduced dramatically control areas are consolidated. The blackout also demonstrated the need for more eyes – both the local asset manager and a regional set that assesses the locality and the events occurring proximately.

I spent a lot of my career in the nuclear business. After Brownsberry, Three Mile Island and other events, the industry was in disgrace. It formed the Institute of Nuclear Power Operations, a self-regulating reliability organization. It worked with NERC and other institutions. I see some parallels in today’s electricity industry.

Question: The western interconnection used to have security centers that are now called reliability centers. Does the eastern interconnection have these?

Response: PJM, New York and ISO New England have a similar history of power pool operations and the communications infrastructure to support such centers. MISO and other areas are coming along. PJM’s control center is the second set of eyes. It can assess the broad area, but it still relies on local control centers. Sometimes local centers can develop a blind spot for some reason. Maybe the computers are on the fritz. Someone could tell them, “I see a problem that perhaps you cannot see,” and then both can decide the most conservative action to take, without arguing about who is right or wrong. I am not as familiar with the western interconnection. Large, regional security-constrained dispatch makes sense because it internalizes loop flows and is more efficient economically. It reduces the need for TLRs. However, the downside to making dispatches too large is that there may be too much on the screen to keep track of. The northeast pools, later to become ISOs and RTOs, piggybacked on the existing local control centers, siphoning off the higher tier information, but leaving the lower voltage transmission

issues of local, but not necessarily broad impact to the smaller areas. The broad oversight and the local set of eyes work in tandem.

Speaker Three

I think what we face as an industry to make our system more reliable and robust has more facets and issues than just the August 14 occurrence. We have been negligent in the accountability of implementing recommendations for many years, and we hope this is just one more call for action, to Congress and to state and federal regulators. Reliability should not only be characterized in terms of large blackouts; there are small reliability problems in every region every day. Most are handled within their systems, but there are more of them. We must move to a system that eliminates even small problems because you never know when they will materialize into something more regional or even interconnection-wide.

The US-Canada task force's final report will contain 30-50 technical and policy recommendations. Most of them are not new. Some will suggest forums or places where issues can be resolved. The interim report was the seventh report issued by the Bush administration about transmission or infrastructure reliability.

A few of the responses to the blackout that should be highlighted include the October 10 letter from NERC's board; the December 24 letter from FERC to FirstEnergy; the MISO-PJM joint operating agreement pending before FERC; and the February 10 reliability requirements submitted to the task force by NERC.

Today, we have more questions than we have answers. Right now we do not have standards for training or certification for operators. Vegetation management is a utility's primary responsibility as the

owner or leaser of a right-of-way. Who is responsible for maintaining and ensuring accountability for vegetation management plans? If state regulators grant the rights-of-way, I believe it ought to be their responsibility. We need stronger NERC monitoring capability. It is critical that the technologies being developed are utilized. We must figure out what creates the greatest visibility for our system

Some of the larger policy issues include comprehensive energy legislation with mandatory reliability. I think we know that such a bill will not resolve all of our reliability problems, but it is a basic building block to construct a more reliable system. The funding mechanism for NERC or a future ERO must be independent from the entities NERC oversees. FERC is ready to do this, but needs legislation. We must have the accountability to the consumers and the ratepayers, and not necessarily to those who write your check. We all know that investment has lagged for almost two decades, due to uncertainty. I think it is an issue even in areas or states that have rate caps. Under a rate cap structure, how can you assure your neighbors and everyone else in your interconnect that you may affect that you can make the investments in the necessary upgrades? RTOs are critical.

If NERC becomes the ERO in the future, it must have accountability measures. What benchmarks will we use to judge NERC and its board? Will it be the time that it takes to implement a rule or will it be a new operating standard? In the future, the highest levels of corporate governance must be held accountable for a utility's reliability plans. They make investment decisions and it is essential that they take responsibility. In the future, it cannot be acceptable that it was the operator's fault or the operator's system that failed.

Again, there are many smaller questions for which we need to find answers. For

example, Canada has under-voltage load shedding, but we do not have it in many places at least in the eastern interconnection. Who would make that decision? What operating conditions are necessary to have a mechanism in place that works and is used? Is there liability for a company that uses load shedding? DOE's May 2002 national transmission grid study coined the term, "national interest transmission bottleneck." DOE will soon initiate a rulemaking to determine the criteria needed to label a bottleneck of national interest.

Demand response means economic savings for regions, as well as reliability. Programs should not be "one size fits all," but tailored to regions, based on the grid's operating characteristics. DOE has some tools and its labs have some expertise that it can offer. It also has many people in different regions working on regional planning who can offer a host of best practices and ideas.

I have been told, "No technology is really ripe to put on your grid unless it's been on someone else's for the last twenty years." However, many technologies will not make the system more vulnerable. There are inexpensive technologies that give real-time grid management data that are relatively easy to put on. The eastern interconnect phaser project is a real-time information grid management system that is almost identical to the one that DOE, BPA and other western utilities worked on after the 1996 blackout. Higher capacity transmission lines that can make the system more robust have been tested for years, but lack investment certainty. At some point, the investment community will invest, as long as we get the certainty right at state and federal levels.

We need to clarify and resolve state and federal jurisdictions. The pending energy bill does not do this. It is critical for reliability, markets and investment to resolve these issues. As we move to a

NERC or ERO reliability infrastructure, issues will arise about refining auditing and monitoring procedures, the composition of auditing teams, and what information should be made public and when. Transmission operators ought to be given the opportunity to discuss reliability violations and to be benchmarked with other violators. Ultimately the way to improve is to let everyone see how the systems are being operated.

Reliability is also an international issue. I think the blackout task force has a great working relationship with Canada. Both countries have issues to address, and Canada is prepared to step up to the plate and do it as a partner. We know we need to modernize our system. The time for pushing the responsibility to someone else, or not resolving the issues that we have known about for so many years is over. We need to act today.

Question: Does DOE's national labs also look at best practices for sting and investment or investment recovery incentives?

Response: It does not. It has multiple reports of best practices in the regions on its Web site.

Question: What is the obligation of one control area to respond to things being seen by another and how are the disputes resolved in real time?

Response: Thirty-five states have utilities participating in RTOs. There must be a mechanism in place, whether it is an interconnection-wide, real-time management system to understand what your neighbor is doing, or someone phoning to say there is a problem. I think everyone knows that if you operate your system poorly, it is to the detriment of everyone in the interconnection. We have a short-term vision where we know what needs to be done, but we never act on it. We need this mechanism.

Speaker Four

Ontario has operated in the competitive electricity market for almost two years. It is currently in the midst of a government-led review of industry policy within the province. Most of its generation and customers are centered in the southern portion of the province between New York and Michigan. There are strong interconnections with New York and Michigan and strong asynchronous or radial interconnections with Quebec. There are smaller interconnections with Manitoba and Minnesota. The generation mix is about 40 percent nuclear, 25 percent hydro, 25 percent coal and about 10 percent oil and gas.

An extremely important part of the market design was establishing the obligation of every market participant to comply with the market rules, which include the reliability standard established by NERC, or by the Northeast Power Coordinating Council in our case. There is legal authority to sanction those who are not compliant. Ontario has found that it has to continually remind policymakers in the US and Canada that electricity is an international product that affects trade and security in both companies and needs to be governed by international rules. The blackout demonstrated in a dramatic way, the density of the eastern interconnection and the importance of effective coordination of transactions between areas.

In my view, transmission is built to carry electricity and it can carry as much as reliable operations allow. It does not really matter whether the electricity transport is local or long distance. What matters is that the operators have the tools and the capability to understand the physical impact of the transactions and coordinate effectively to control them as required to maintain reliability. The physical path of transactions must be understood, whether or not it is the same as the contract path.

Due to the physics of the system, many portions of the eastern interconnection must deal with unscheduled or loop flows. Loop flows have been around a long time in Ontario. The province shed firm loads to stay within limits in 1998 due to unscheduled flows because at the time, there was no way to know whose transactions caused them.

Today, there is far more information on transactions. We know where they are sourced and synched. Our tools could use improvement, and some inputs are not kept up to date all the time, but we are far better off than we were ten years ago. TLRs are a blunt instrument that can take far too long to resolve emerging or urgent violations of interconnected reliability limits. More frequent equipment status updates and better tools and training will help, but I do not believe they will ever be as effective as broadening the scope of regional markets and managing congestion through the most effective redispatch.

The blackout was more severe in Ontario because complete restoration of normal supply was delayed for over a week. A generally tight supply situation that had continued from the summer of 2002, uncertainty about how much support New York and Michigan could provide and the slow return of some of the province's older nuclear generators because of the way they tripped initially caused the Ontario government to request voluntary curtailment by all customers. Industry, business and homeowners responded by curtailing consumption of 4,000-5,000 MW the following week. This dramatic response was encouraged by media interest. As you drove to work, radio stations announced which large industries had taken action and stations had people knocking on doors to ask why the ac was still running.

As severe as the impacts were, it was fortunate that the blackout did not occur in mid-January when it could have been a

public health and safety disaster. We need to consider this because today's society cannot tolerate preventable, widespread blackouts.

It is disturbing that many of the initiating events were the same for blackouts in the past. Our industry just has to break this pattern. This blackout demonstrates that our complex systems are vulnerable. However, policymakers must ensure that is reducing vulnerability to widespread blackouts, that they do not throw away some of the other benefits. For example, if the integrates system is balkanized to prevent cascading outages as some people have suggested, we may all become more experienced in restoring local systems. I am disappointed with the lack of progress of electricity legislation in the US. We blacked out 50 million people: what more evidence do we need?

Electricity trading markets and reliability are so tightly linked that their coordinated management cannot be disbursed. The rules, the roles and the authorities must be clear. I believe that properly designed markets can deliver reliability, but in any real-time circumstance where they cannot yet do this, there must be no doubt that reliability must rule the day.

Discussion

Question: The maps of reliability councils and RTOs do not align. Why is this? It is a problem if it continues?

Response: It would make sense to have them congruent. To the extent that reliability councils do survive, we need to have the RTOs and their boundaries better defined. Once RTOs are established, it will make sense to realign any functions that remain. In PJM, most of the work of the reliability councils is subsumed by the RTO. The councils have more of a stakeholder oversight. For now, there are members that want to have the

independent oversight of the ISO. To a large extent, NERC is leaning on the existing councils to perform some of the audit functions that historically were performed by the councils, perhaps not as rigorously as is now being suggested.

Response: Reliability councils are designed around systems that were planned and built as a unit and that put markets first. If you put reliability in front of markets, you first build a reliable system and then allow the markets to work around it. There are natural areas of this country where the systems are large enough to be reliability centers.

Response: The regions were set up in 1965 so it is no surprise that situations, operations and the political landscape have changed.

Question: Would it be possible federal assets to lead the way in showing how they could be operationally integrated for purposes of enhancing reliability and efficient regional markets? For example, the Western Area Power Authority is proposing to establish its own control area. I believe that the California ISO thinks that WAPA should be part of CAISO.

Response: It is a challenge. WAPA and the munis have statutory issues they must resolve. DOE will continue to work with them. These things take time.

Question: If a control area becomes too large, does that increase the likelihood of cascading failures, as opposed to a more manageably sized RTO or ISO where neighboring areas could disconnect in a dire emergency as PJM and AEP did last August?

Response: That separation was not human-driven; it just so happens that the locus of voltage and current swung through some relay settings. Having 140 control areas is a vestige of the past, when

vertically integrated utilities planned, owned and dispatched their own generation to serve their own load. They answered to their state commission for the delivered cost of the electricity produced under that regime. They build transmission primarily to connect the generation they wanted to build to their load centers. My guess is we could get down to 10-12 without producing things so large that they would surpass the ability of today's computers to manage the system.

Response: The right number of control areas will require a lot of analysis. I think you should have to demonstrate that something absolutely improves reliability, is critical for either operations or reliability and that generation-only control areas are not beneficial to the system. I think FERC ought to have a role in approving control areas.

Comment: You either need to have few enough control areas so that effective coordination can occur, or you need to give some of the obligations and roles to reliability coordinators, if you like, raising it up a level to someone with broader oversight. I get nervous when people talk about setting up the system so that it will break apart in times of most urgent need. There is a reason why the eastern interconnection is operated as a 600,000 MW machine. It provides tremendous benefit day in and day out, absorbing the sometimes very large perturbations that are always occurring but can still be sustained with that large a system.

Comment: Almost every utility will have a control area that does nothing but switch. It is question of what function the control area does. I think you can have RTOs that are too large to manage and that it makes little sense to have certain systems inside certain RTOs. Texas does not care what the northeast does. It might have some impact someplace else, but it is so small, you could not even see it. Design around

what computers and people can do. Keep it as tight as you can around areas that are really important to each other and make sure you can coordinate across the two.

Question: I think the two parts of a control area are controlling transmission and reliability, and generation and load balancing and economic dispatch. Can you distinguish between generation and transmission control areas and does it make a difference?

Response: I think a control area's prime function is balancing load, generation and interchange to maintain frequency. Therefore, it must have the tools and situational awareness to manage the transmission system that is part of the area. It does not make a lot of difference whether or not there are different sub-crews or dispatch centers to throw the switches.

Question: If you want to collapse control areas into an RTO, would it perform generation and load balancing and also economic dispatch?

Response: Someone else could perform that function.

Question: If legislation sets up a self-regulating ERO, where are the boundaries between government and self-regulation?

Response: I think transmission rates should fund NERC, not the government, so that NERC can make completely independent judgments.

Question: If FERC transmission rights, how does that work in retail states?

Response: To put this in perspective, NERC's 2003 budget was 12 million dollars. I think funding that is independent of the industry it regulates, even if it is through a third party, is a prudent mechanism.

Comment: One of the lessons learned from the blackout is that perhaps NERC has not been rigorous as it should have been.

Comment: My concern is not the amount but what happens when a state decides it dislikes what NERC does and withholds funding.

Response: Saying that we cannot have a mechanism like this because it presumes that NERC is no longer independent, makes no sense. Do not change a basic philosophy and create a new tax to pay for something when you are really saying that you want NERC to be independent. NERC is a good organization. Does it have some problems? Can they be fixed? Can it be managed differently? We can do all of these.

Comment: I think a funding mechanism that is designed to collect \$12 million from industry is inexpensive to implement. NERC's sole responsibility is to facilitate the rules, guidelines and accountability mechanisms to ensure that the system is reliable. It must have some independence and ability to be the tough guy.

Comment: NERC has an independent board, but the problem is that it is voluntary. We need to enact reliability legislation to require mandatory participation.

Question: Does the Bush administration think we are better off waiting to pass the entire energy bill rather than the reliability part?

Response: We are better off as a country making sure that it is passed in its complete form because the bill contains many critical provisions.

Question: Do you predict that it will take another large-scale event to implement some of the recommendations?

Response: It is inevitable with the machine we have that blackouts will occur in the future. We can minimize the possibility, but I hope that it does not take one to get us to act.

Comment: INPO has demonstrated that you need strong enough enforcement authority. Although it does not levy fines, it meets with boards, contacts CEOs, uses the media as a bully pulpit, and refers things to the NRC, eventually receiving the attention that gets problems fixed.

Question: One side of the transmission debate says there has been too little investment, while the other says we need the right kinds of reliability investment – sometimes transmission; sometimes generation; to change the flow, or sometimes a robust demand response. What philosophy represents the best national policy?

Response: The latter. I also believe that markets with the proper pricing signals cause the investments to occur in the right places at the right times.

Response: I think the steady decline in transmission investment is catching up with us. I believe that we minimize the amount we need through technology and LMP, if that mechanism is available in your region. At some point, we need to realize that our transmission highways must become super highways and our rural roads four-lane roads because the economic transactions are growing larger.

Response: My experience is that if there are competing bids, transmission often loses out, so then you count on generation or load response. You stop planning your transmission. A year-and-a-half later, the generator tells you that conditions have deteriorated and it will not build, or it will put it off for four years after you need it. I am becoming increasingly convinced that we need to make some investment in

transmission to allow some of the competitive forces to occur.

Question: Should NERC address transmission at the local level? Regional reliability councils traditionally have only addressed widespread cascading outages.

Response: NERC looks across the broader regions and the regional reliability councils look more locally.

Comment: Make sure NERC criteria are done on a local level and integrated on a regional level.

Comment: If the Midwestern region had an LMP market with an ISO, when four pm came on August 14, the system would have been significantly reconfigured. A PJM would have sent price signals that would have started telling generators in Michigan and Ohio to change their dispatch. They would not have to know that a specific generator or line was out.

Response: I think it would have helped but I do not think it would have stopped the beginning of the cascade.

Comment: The system would have been in a different configuration so the cascade may never have started.

Comment: You make too many assumptions. It does not matter whether or not you have LMP and ISO, if you do not know that your lines are nearly sagging into trees. You must know what your system is capable of operating to.

Response: They went to N-4 or N-5 without the dispatch that occurs automatically, without phone calls, without telling generators to change simply because they follow the pricing signals.

Comment: Deregulation seems to have very pernicious offspring called price caps

and rate freezes that I think have some impact.

Response: We have a four-decade history of recurring blackouts in different portions of the nation with similar, if not identical, root causes identified. We have not had deregulation for four decades nor even uniformly across the nation.

Response: I do not think that retail markets are a contributor to reliability problems. The vast majority of this country's transmission was built with a nuclear plant or a coal plant. When utilities stopped building their own generation facilities, the vast majority of the additional transmission stopped and that was exacerbated in 1992.

Response: While plants continued to be built, they were built in a way that used up transmission margins instead of adding to the margin or to the system itself. There was a kind of doubling effect: there was more generation but instead of adding to the reliability of the system, it was deteriorating or taking away from the margin that was built into the system for many reasons. It has not been replaced; new generators are not replacing it; and utilities do not have the money to do so. They would not know where to replace it because the market changes every month. You are no longer building for the local requirement, but for an undefined national requirement.

Response: There may be good reasons why transmission investment has declined or transmission has not been built, but I do not understand why at the same time investment in tools and trailing for operations would have decreased. These are cheaper than building more transmission and essential the more constrained the transmission becomes.

Comment: There have been upgrades in computer systems and I other tools across

the country. They may not be the right investments.

Comment: BPA has been trying to put together an RTO for eight years. I do not know if people on the east coast appreciate the statutory and cultural

limitations and also our hydro and the different configuration of the transmission system that limit what can be done and how fast. Some of the problems in industry have only made it more difficult to move forward, but we are trying.

Session Two. The ISO as the New Utility: Bigger Footprint and Federally Regulated

A frequent comment heard from all quarters after the August 14, 2003 blackout was that with rate caps in effect, utilities lacked any real incentives to spend on maintenance and operations. The logical deduction from such statements is that service quality is likely to decline under capped prices. Experience in telecommunications, especially in the Midwest and West, has reinforced that point of view. A number of states have signaled that they fear such an eventuality because they have tightened up their rules governing service quality. Is this common perception of service quality declining under price caps or rate freezes accurate? Do frozen rates change incentives for utilities? Do they create a different set of incentives than regulatory lag did under traditional rate of return regulation? How should service quality be monitored and standards enforced? If service quality does decline, how should regulators respond? What incentives, if any, should be put in place? What sticks can, or should be wielded? Are there appropriate market mechanisms to be brought to bear, or should “old-fashioned” regulation be applied?

Speaker One

I wish we had electricity markets. I wish there was a giant farmer's stand somewhere that bought and sold kilowatt-hours. Instead, we have models that simulate markets. In New York, just to run the day-ahead market, there are seven iterations to optimize the system. Obviously, the engineering approach is to operate safely, reliably, minimize the risk of failure and, frankly, keep firm control of the reins.

But the invisible-hand approach says the less unnecessary interference in the market, the better. If the price signals are correct, they will come, and the market works best when there are assurances that the prices seen are the real ones. Electricity has been regulated for a hundred years. There was no price volatility in most places; the rate you saw was the rate you got. Now all of us must tiptoe our way through various political

considerations, because ISOs are a creature of the federal government.

New York needs 37,500 MW on a system basis for peak energy needs, plus 18 percent reserve margin – the one-in-ten-days in the state. Seventy-five percent of the year, the loads are less than 24,000 MW, meaning that 75 percent of the year, up to 13,000 MW sit idle, absorbing costs and not making a penny. Therefore, it is only a small portion of the year where some plants are allowed to recover their money over a small portion of hours.

In capacity markets, generators do not really have to get all their opportunity costs. If New York begins to cap the amount that anyone can bid, or if you bid so far out of your marginal costs, that we step in to fix the bids, the free hand begins to be tied up and we are now using proxy for market forces to resolve the issues. I am not saying that these compromises are

incorrect – we need actions to mitigate load pocket concerns.

In deciding that demand-side programs are also important, but were not fitting our developing system, we made some adjustments. We were even so successful in lowering the prices and making sure that no one could gouge the market that we found that the prices were not really reflective of what they should be in scarcity situations. Now we have begun implementing scarcity pricing to get prices back into balance.

People try these market tweaks and fixes to make the marketplace work in a politically acceptable way. But then they begin to regard the ISO as the organization that can accomplish other things. Fuel diversity is one such issue in the state of New York.

Unfortunately, the MW we could get from renewables on any realistic, cost-effective basis are small. No one is building nuclear and Ontario wants to shut down its aging coal plants. That leaves natural gas.

However, we may not have the appropriate incentives in place. There is a lot of responsibility associated with the installation of dual fuel capability – storage requirements, costs and environmental requirements, and I am not sure if the market reflects those to a large degree. Unfortunately, the natural gas infrastructure may not be keeping up, especially on peak days. Now if an ISO sees an approaching reliability problem, should it step in and offer a solution? We say we want the marketplace to move us to alternative fuels, but that is not happening.

People look to the ISO for help with renewable portfolios, long-term contracts to spur financing, special pricing provisions to keep certain plants operational, transmission and a host of other temptations. Inevitably, this will

lead to an integrated resource planning process.

When does an ISO step in? First, it should look for either market-based solutions or a proxy to market-based solutions, rather than direct intervention. It should ask why the market is not providing solutions to the problem and whether the market design is flawed, or it is something more systematic. Sometimes one fix causes other problems. A political consideration may be preventing a solution, or moving you to a specific solution, and the political consideration may be come from different directions.

The ISO should always try to make the market work to drive the solutions. I believe that market adjustments are preferable to market interventions. For me, deregulation either succeeds or fails on the ability of private money to go into the system. Nationwide, probably over \$20 billion of private investment did not go through anyone's rate base. But some companies are in trouble because they misjudged some of the risk. If the \$20 billion done by private investors had been done by regulated utilities, it may have been \$30 billion. The same cost incentives were not there for people to take to keep prices as low as possible. The real question to ask is that if we take this market fix, will it slow the investment of dollars, and will that cause skittishness? We need to consider the views of the investment community. Reliability must always be paramount, but sometimes we must think about short-term versus long-term reliability. There are fixes that could be made in the name of short-term reliability that can threaten long-term reliability. If there is not enough private investment in the system, we cure a short-term problem and cause a long-term one. Sometimes, we just have to trust that the market will work. I think people are very impatient to do that in these new markets.

Can we define the line where we step in or not? I am not sure if it is black and white. I do know that ISOs are an evolving experiment and that the experiment is working well and we are all learning as we go along. We always need to keep our core missions of markets and reliability in mind as we make the changes, tweaks and adjustments.

Speaker Two

Order 2000 probably did a good job in setting forth what it wanted to see at the RTO, but it did not go the next step and define the RTO's primary focus. We have spent a lot of time in this industry, debating whether RTOs should be for-profit or not; and whether there should be ITCs. I believe we ought to first figure out its functions and what we want an RTO's board to focus on, and then worry about the corporate structure and form that follows from that.

There are different scenarios. One is to run an RTO like a business. That sounds reasonable, but what is the business? Is the RTO a grid management company? PJM, for example does not physically control anything. It operates on a system of sending price signals to which generators respond, but it does not trim the trees.

Maybe an RTO is a company that provides critical information about LMPs and the state of the system to which market forces respond. But the Midwest has multiple control areas, so you do you package all of that information and send it out in a coherent form? What does it really mean to be an information provider in such a diverse system?

If the RTO is a grid manager and information provider, to who is its board accountable? There would be strong accountability to the membership, if it were a private company. But the RTO must also be independent. How do you

protect minority rights when you are a manager and not really a judge? Does this send a mixed message to the board members who are trying to understand their roles?

It makes sense to say that the board's focus ought to be on the efficiency of the RTO's operation. But others are also looking at operational efficiency, like NERC, FERC and the market monitor. Therefore, how much authority does the RTO board have versus these entities? At the end of the day, where does the proverbial buck stop?

Speaker Three

I am defending states' rights and ask why the states are deferring to the ISO. First, a wave of cost-of-service (COS) nostalgia is sweeping the country. Before open access was accomplished, utilities claimed that over \$200 billion in stranded costs that were above the market would become worthless if competition was instituted. It turned out that some fossil fuel plants were significantly undervalued and they recovered about 200 percent of book value. Cost-of-service says that these assets were overpriced earlier and that people overpaid for them. I challenge anyone to calculate COS for IPPs that do not have life-of-plan contracts for their units. If you get the price cap wrong, how do you ration capacity?

These are some of the reasons why we moved to competition. Competition is relatively new for the industry, and the first adapters all had problems. Even PJM's first market design failed miserably. In this transition from the old to the new paradigm, I believe that a good market design leads to better reliability. I do not say we will prevent all blackouts, but we certainly can improve reliability. The toughest change is cultural. Will we buy the market theology or the cost-of-

service theology? Do we have a set of ethical practices yet?

The ISO's role and that of its independent board is to facilitate several stakeholder processes. As the market operator it should not be a market participant, nor should it be the umpire that decides the play. There are problems with market power, some casino issues with bidding, and free riders. FERC's "white paper" said we are going to buy into a lot of regional variation. We do not see it doing much damage, and we believe that the states should have been in that position in the first place, and maybe SMD did overreach at first. The biggest problem is that mitigation and strategic behavior are error-prone and we have to learn either how to live with that or resolve it. I think SMD and its mitigation are FERC's attempt to carry out this responsibility.

A market is efficient and competitive when there is truthful bidding and some incentives for it. Then you do not have a demand curve for reserves, you suppress the revenues in the spot market and you do not get investment. If you design the spot markets correctly, you can recover efficient investment and then the resource adequacy or the forward markets become hedge instruments.

Our electric system is plagued with externalities, some of which we are willing to accept. For example, we find it legitimate in competition to accept the externality of a business stealing and thus creating a situation that drives people out of business. The problem is how much the beneficiaries should receive for the property rights for which they paid. Or if market response time is slow for the demand, the externality is a system collapse or a blackout. If we do not panic and we are willing to wait, at some point, maybe even in real time, there will be faster responses and decent resource adequacy. We also tend to panic about ISO exit rules that say you can exit with

60-90 days' notice, and insist on RMR contracts. Withholding is also an externality. The panic approach is to do nothing, on the theory that high prices are good for people and stimulate investment. Then we overreact and over-mitigate the market and create investment problems in the future.

In areas that were not tight power pools, it is difficult to convert 888 rights and network service rights into FTR obligations. The problems are manifesting themselves in the Midwest and now we are trying to force fit the conversion. We hope the future offers FTR options, flowgate rights, dispatchable flowgates and even admittance pricing.

I believe that having either FERC or RTOs in the business of resource adequacy is not a good idea. An RTO has very little credit to fall back on and therefore must use the credit of the end-users. I believe that states have the right under the US Constitution to subsidize entities inside, but not outside. States must be in the business of demand response and probably should manage the transmission rights and the risks of native load. It is important the states be in the business of long-term generation contracts on behalf of their customers, or at least to decide the contract and hedge positions in the spot market.

The hope is a long-term market disciplined by entry that is essentially controlled, especially in generation, at the state level. One reminder: you benefit from high spot prices when you are long in resource adequacy. If you want retail competition and resource adequacy, you could establish a POLR operation to maintain the long-term contract position or long-term resource adequacy under state or local regulation. But you must balance your operation so that it does not become beneficial for people to return to POLR when it looks good or exit when it looks bad.

The federal roles are: interstate markets and interstate reliability including the possibility of curtailments, to ensure that a problem that may begin in one place does not spread across state lines; transmission rights and short-term market designs; oversight of the planning process; prevention of cross-state subsidies and possibly backstop transmission siting. Transitions are not easy and it takes time to convince people to move from one paradigm to the other. We simply have to keep trying.

Speaker Four

I have been in this industry for thirty-seven years. I take a minimalist view about what the RTO should do. I think that FERC Order 2000 got it right, though there are a few things with which I would disagree. The following are my thoughts on RTOs.

I believe that independent boards are both valuable and important. I believe that we must be careful to define the terms, RTO and control area. I think control areas should be much larger but not so large that the operator does not know the system. I do not agree that you can have both generator and transmission control areas. To mitigate line flows, I can redispatch generation to avoid overloading or I can drop load. Since the second is the least acceptable to most people, we need a control area and an RTO with the authority to dispatch generation. The inability to dispatch generation on August 14, 2003, created a lot of dilemmas. I think that short-term reliability is an RTO responsibility because it can access what is happening and make the decisions. Running the eastern, western and ERCOT systems with different congestion programs leads to confusion and seams problems, and therefore congestions management and tariff design and administration are major issues.

An ISO needs a way to identify the reliability resources that it can use. I believe markets are the way to do that, although California probably went a little too far in the reliance it put on markets.

The electric industry must have more transparency. Some people say that confidential information should not be seen by everyone, but I believe that you if you do not give it to everyone, the big ones and the smart ones will get it anyway, while the little ones will not and then the market starts to fall apart.

I think planning and expansion is a joint responsibility with state involvement. ISOs or RTOs are in the best position to coordinate everything. I also think that they are the best market monitors because they can see everything minute-by-minute. However, they have no subpoena authority and no method to extract real information from the market participants. Without these, I think ISOs can do a tremendous amount of damage.

For example, if I reported in an open forum that the XYZ Corporation was exhibiting some strange bidding behaviors, but had no proof because I could only see part of the information, the data should be provided to an external source that can then determine whether there was a violation. If the ISO provides the information, I think FERC and the states should develop the monitoring function. ISO's have a wealth of information and it ought to be made accessible. I think an RTO should not be a marketing warehouse for marketing hardware and software because it detracts from the business of being a service provider.

In summary, FERC's Order 888 facilitated the structural reorganization of the electricity industry but the functions ascribed to and assumed by RTOs started blurring the lines. In the end, I think the

market will solve our problems and that RTOs should focus on the core business, be the spokesman for problems and bring them to policy-makers for resolution.

Question: Are we asking states to have a compact in which they agree to impose the same level of resource adequacy in a common region if the ISO does not do it? If states impose a requirement only on POLR providers, is there a minimum amount that must be in the market to provide enough incentive for investment to cover an adequacy requirement over the long term or must all resources be subject to that long-term requirement?

Response: The question you are asking is how establishes and mandates what must be procured. New York has a mandatory reliability council to do this.

Comment: The ISO must be able to curtail entities that are not resource adequate. We do not want to let the process go so long that we have to start curtailing people. It is a state decision. I find it very uncomfortable for the federal government to be making decisions on the levels of insurance and adequacy for the citizens of a given state. There is an insurance value that may argue for some kind of collective action, but the ISO is not the appropriate place to do it. If you do not want retail customers to be exposed to prices and to be curtailed, then you do not want them on LSEs that are not resource adequate. If you believe that long-term contracts are necessary or that they lower the costs of procuring reserves, then make POLRs responsible. If you leave the POLR, you may have to leave with the installation of demand side curtailment equipment so the ISO or the LDC can strategically curtail you in certain situations. While that is a burden for some LSEs, I do not see how to reconcile an LSE that does not want to sign a long-term contract and that does not want to have a long position with the idea that it can come and go. If someone leaves the system and then returns to the POLR, I

think that the person begins anew. If someone decides to leave, he receives a share of the POLR's portfolio at the time and it could be tradable. But we must rethink the retail access rules in order to make the system work.

Comment: Who bears what portion of the obligation? If there is a minimum baseline and a state decides it wants a higher level of adequacy, the RTO can administer such a regime.

Question: When we talk about curtailing loads that do not have long-term adequacy, does it mean we enter a forward contract that is not covered?

Response: You must make strategic decisions when you go into a reserve shortage. If you are willing to let the price mechanism work and you have the ability to self-curtail, people will do that. You do not have to do this through the exercise of market power.

Comment: I believe ISOs are being pressured to mitigate price volatility through political pressure. The regulatory protections to mitigate this volatility in the short run are causing long-term resource adequacy problems because they reduce the incentives to build. A sensible interim model is to keep small customers on regulated service and let the big ones deal with the consequences of high prices in the marketplace. If we really believe that there is a free rider problem that cannot be solved, then electricity truly is a public good and it must stay a regulated monopoly. Between prices and curtailment there ought to be a way to solve this problem.

Response: I am not sure I buy the premise that it has mitigated to the point that the market is no longer functional. For example, scarcity pricing is trying to fix exactly the problem: that when things are tight, prices accurately reflect this situation. And the demand curve tries to

address the boom and bust problem in the ICAP market. What needs to be fixed is to encourage LSEs to go in for longer-term arrangements and give them some comfort that a good contract will give back to ratepayers, while shareholders will have to “eat” a bad one.

Comment: We have tried to take the volatility that comes from the exercise of market power out of the market, but then put back in the volatility that we should receive from legitimate scarcity pricing. I think that almost all of the ISOs are moving in that direction.

Comment: We are dancing around the more interesting question about who decides. State commissioners have the fiduciary obligation to their consumers to mold the rules correctly and I would rather have them decide than either FERC or the ISOs.

Question: Do performance objectives or corporate goals for the ISOs include ensuring that a transmission project gets built; implementing demand response or achieving some targets of demand response; and minimizing price volatility? Who establishes such performance goals?

Response: In PJM, those goals, including customer satisfaction, are primarily related to operational issues, with specific goals for each individual division. There is no agenda that says that one program or another must be implemented.

Response: The New York ISO has developed a long-term strategic plan vetted by all of the market participants. It was out for six months of comment. The operational goals are related to the contents of the plan.

Response: I think it is the states’ requirement to identify the capacity that LSEs must have under contract or whatever. The real question is how you count the resources. Do you allow demand

side? Do you allow units without water behind them? Once you decide that an LSE will provide x capacity, if you have a market that works well and someone starts leaning on someone else, they will be stuck with the high price that occurs. If people have not provided and you have to drop load, you will drop the entity that lacked the reserves. That will not happen too often before the entity puts it in. For non-FERC, non-PUC jurisdictional entities, first you would penalize them financially, because you have to go out and buy power. Second, when you must drop load, they are the first to go.

Comment: There has been a brain drain as many people leave state commissions and utilities for employment at ISOs. Now, we expect ISO to do things that may not have occurred in the past because they did not exist.

Response: If we create an institution that does not meet the needs of the policymakers and politicians, it will not last.

Response: I think that FERC’s role is to make sure that the costs incurred by states stay in the states.

Question: If PJM tells us we might need more generation, no one really has the authority to order it with the way we have restructured. Have you thought about a situation in where legal authority is given to a regional organization?

Response: If the generation you need is not being built, what is wrong with the market? If you get everything right and things still are not built, what is the fallback? It is too easy to go to that part first.

Comment: There are incentives through the ISO.

Response: I do not even want to call them incentives. I want to call them proper

market rules. If I have LMP and you do not, that is a market problem. In the northeast, everyone built generation in Maine because it was easy to build there. If New York had taken that same route, there would be a lot of upstate power plants and nothing built in New York City. But with LMP there are three generating units in construction right where they are needed in the city. It is not the ultimate solution but at least we have them where we wanted. Other market flaws also can make it easy for ISOs to fall back into the mindset of regulating a way out.

Comment: I have not seen many ISOs or RTOs using demand-side management, which is obviously more economic than building new generation.

Response: We are using DSM in the sense that we pay LMP for people not to consume.

Response: PJM is the only eastern ISO that has not yet embraced scarcity pricing. PJM's load-pocket mitigation scheme is not very conducive to new peaking plants because you get variable cost plus ten percent if you are in a load pocket. One of those entities will set the market-clearing price. The peaker will only recover its marginal cost. It may be able to receive a little more money in ICAP. Without the demand curve for reserves, there is no other way in the spot markets to recover its investment costs.

Question: I think we are trying to force fit or force fix regional market concepts onto existing structures. Some of the structures that come to mind are state and federal jurisdiction and authority; the physical existence of significant transmission constraints; the hundreds of traditional transmission-owning utilities that have grown over the years from the time when everything was very localized; and the non-profit ISO or RTO business model that grew out of the tight power pools in the northeast. Is it possible to achieve the

objective of broad, regional, reliable, competitive markets without significantly challenging the continued existence of these structures?

Response: ISOs are also evolving entities.

Response: As a former regulator, the good old days were not so good.

Comment: If we could have started the ISO and the electricity system from scratch, obviously we would not have broken down jurisdiction by all sorts of different authorities and the islands would look different. Of course there have been glitches along the way, but areas with ISOs have seen the most progress in terms of new generation being built and private investment occurring. My concern is that we have to adapt, evolve and change the market rules along the way.

Comment: I cannot figure out how a for-profit ISO will establish clear goals, measure performance and motivate in one direction or another.

Response: A classic problem in utility regulation is the lack of a model to reward efficient behavior by employees. When a utility would present its capital investments, regulators would basically look at the employee cost as cost.

Comment: We must decide whether we want incentive or ownership of assets, the definition of "for profit" and what kind of structures we want to create.

Question: Are there significant, unrealized opportunities for ISOs to deliver improved environmental quality to constituents? If the answer is yes, what incentives can we create?

Response: The way to motivate environmentally preferred sources is to ensure that people can bid in a price that is less than what the market is paying.

Response: I do not think we have to incent or subsidize things to do proper environmental stewardship. We do need to make sure that different technologies that we did not think about when this market was designed can work within our system.

Response: I champion scarcity pricing. I have always argued that if you suppress the real-time spot market price, you do a disservice to solar. I also think that if you view the ICAP market as essentially an option price into the spot markets, you get a much better deal for wind. I would like to see the ISO do green accounting, since it already has to pay attention to the physical generators on its system.

Comment: The possibility of a tripartite arrangement among FERC, the states and an independent market monitoring entity does not sound very workable. I think the market monitor ought to be an extension of FERC.

Response: Federal and state regulators have the authority to subpoena records and find out whether market behavior is inappropriate. ISOs can identify anomalies and bring them to the regulators' attention, but they are not the policemen or enforcers.

Response: If we do market mitigation without having someone from the outside looking at what we do, we may do it wrong. I think there are some checks and balances that allow people to do what is correct and allow the regulatory agencies the comfort that people are doing it correctly.

Comment: I wonder if we are kidding ourselves that we are trying to solve product volatility either through interrupting customers or having operating reserve prices go high.

Response: As I approach my day-ahead market, are there sufficient generating units that I can put on line to meet the next

day's load requirements? Granted the west does not do much voltage reduction because it is stability-limited everywhere. But if I get into those reserves in an isolated area, we will not drop load unless we are impacting the reliability of the western interconnection. If not, we will cut the reserves in that area and they will be at risk. Both day-ahead and real-time have a balanced schedule requirement.

Comment: The idea behind the spot market was to get away from a balanced schedule requirement.

Question: Balanced in aggregate or balanced per LSE?

Response: I will look at the individual capability to serve almost the local reliability problem, and then at the total market, to bring on enough generation with the understanding that whoever is low pays the spot price that comes from having my units on.

Comment: The MD02 market design looks much like the market design in the eastern US. It has a day-ahead market and a unit commitment.

Question: When there are free-flowing ties over multiple states, we have created something that I do not think a single state can solve. Are we still attacking the symptoms of the energy price caps?

Response: We will always have to work around price caps. We have to solve both the price cap problem and the market power mitigation. You cannot ask generators not to exercise market power and once in awhile ask them to exercise it because the price is not high enough.

Comment: I could not sit in my state as a regulator and say it is okay to curtail the customers of an LSE that did not ante up. It seems a bit disingenuous to suggest that somehow curtailing their customers would

be more palatable to a state commissioner than having uncapped energy prices.

Question: Why would it be fair to curtail a customer of an LSE that did line up reserves?

Response: We determine if there is a need for curtailment and give it to the local transmission owner who actually does the curtailment.

Comment: Government's job is to protect those who cannot protect themselves. As a regulator, I am in charge of making sure the LSEs do their job, which means that they have to have more capacity than what they think they will need because they could be wrong. That means I am wrong and that means we are in deep trouble.

Comment: No matter how elegantly we design a market, at some point the political process will pinch. The reality is that at we will have to socialize the pain.

Question: Some states have capacity requirements or obligations to serve in retail settings where there is no choice. What happens when other states within the same RTO regime do not have those?

Response: The overall need for capacity adequacy exists, whether or not you are in a retail environment. Somehow, we must marry an RTO's obligation with a state's. I would not want to do one without the other.

Question: If a jurisdiction has multiple LSEs and an uncertain customer base because they can switch between LSEs how can an LSE ever sign a long-term contract?

Response: Maybe IPPs can do better. Although there is uncertainty for many, there may be opportunities for shorter-term contracts that suffice for some appetites.

Session Three. Choice of Fuel Resources: A Role for Planning and Allocation in a Market-Driven Environment?

Most generation planned and built in the United States in the past decade has been fueled by natural gas. Gas seemed plentiful, the repeal of the Fuel Use Act reduced regulatory and legal barriers, gas plants were less capital intensive and less subject to construction and planning risks than alternative generation, prices were reasonable, and environmental and siting difficulties seemed minimal. The attraction of natural gas has changed dramatically with rising gas prices and renewed concerns about long-term supply. Indeed, the concerns are perhaps even more profound than simple economics. The likelihood of increased LNG imports raises national security issues. Could rational, market-driven responses to rising gas prices be discouraged, if not effectively precluded? Is it realistic to rely on the market alone to produce a sufficiently diverse energy resource base? Can a market approach to fuel diversity overcome market imperfections? Advocates of renewables have contended for quite some time that portfolio standards should be imposed on the power sector. Would it be wise to adopt such standards, but expand their applicability to all energy resources? Alternatively, should we utilize planning in assuring a diverse resource base? If so, how should it be done, and who should carry it out?

Speaker One

My company is the largest IPP in the US with 87 plants and about 23,000 MW in

operation. We own about one TCF of gas in the US and Canada. In 2003 we delivered about 3 ½ percent of the natural gas used in the US. A diverse

geographical fleet helps us trade across markets and diversify our earnings, for example when prices are high in one area and not so high in others. My premise is that natural gas will remain the fuel of choice in the American, Canadian and Mexican markets for some time to come. It responds very well to market forces, despite the price spikes that have raised questions about whether we are picking the correct fuel. When it reaches \$5, it promotes the addition of new reserves and the entrance of new gas into the system.

We manage price risk by owning enough reserves in the ground to supply about 25 percent of the fuel stock needed for our plants and through our longer-term agreements with major gas suppliers.

Some estimates show that the amount of recoverable reserves in North America alone is enormous. These days, there is talk about building new re-gasification facilities and LNG. Of course consumption is slowly increasing. But the new modern plants consume about 40 percent less natural gas than traditional gas plants. During the height of the building period January 2002-January 2003, MWh generated from natural gas-fired plants increased by 8 percent, but the consumption increased by only 2 percent – an indication that as you build new facilities, you can do it more efficiently. And as you know, gas is extremely clean; uses less land; consumes less water; and reduces global warming by the reduced emission of CO₂.

I believe that price and supply are driven best by economic and environmental forces. Governmental intervention and attempts to manage the selection of fuels that failed to result in the deployment of nuclear technology and ultimately lost the public's trust in the 1970s and 1980s and the Fuel Use Act did not work out. Although the government has spent \$7 billion to introduce clean coal technology into the US, I think we can all admit that it

has a long way to go. And even though we have renewable resources, it is difficult to deploy them in sufficient quantities that really make a difference to the fuel mix in the US. In my view, market forces should be left to determine both the selection of fuel and the price and supply.

Speaker Two

I do not need to remind you that many of our most promising resource options actually involve getting more work from less fuel. The question is whether a market approach can work or we must rely on state socialism infused with arbitrary mandates to get the new resources and investments we need. I believe that the merchant power model is dead and that for most of the country, the resources will be the hometown distribution utilities for the foreseeable future.

This does not mean that we abandon all retail competition. We must have the capacity to opt out of a utility-based system of resource portfolio management for those who are willing to assume the risks.

A hometown utility with which I am familiar and that takes its portfolio management responsibilities seriously has an analytical process in which its resource portfolio manager looks at risk; uses competitive procurement to meet identified needs; selects the best supply and demand resources including energy efficiency; and assigns a dollar cost to carbon emissions from every source. All of this activity occurs in a multi-state system that lacks any mandates.

The utility has learned that there are two large distortions for allocating resource investment through portfolio management by utilities in the market-based system. The first is that efficiency investment by the portfolio managers is less profitable than generation investment because the

managers' fixed cost recoveries are tied to its retail sales volumes. The second is that contracted generation secured under long- or short-term commitment, is inherently less profitable than generation the utility owns, because there is no mechanism for earning a return on contracted power.

Neither of these problems is intractable, but we must acknowledge that they are pervasive across the country. I also think we need to anticipate the migration of these concepts and problems to the natural gas industry. The American Gas Association has called for more diverse resource portfolios for the country's natural gas distribution companies, and has called on state regulators to help encourage that. It was ironic during the debate about the Alaska natural gas pipeline to realize that Congress was really trying to create the functional equivalent of long-term purchase contracts for the natural gas available in the Alaskan fields because there was no capacity in the existing natural gas distribution industry to execute long-term contracts, for reasons well known to anyone who recalls the history of the gas industry in the 1970s and 1980s.

Overcoming the inability of the natural gas distribution companies to execute at least some longer-term commitments, along with their spot market purchases should be an urgent priority, as should the capacity for the industry to invest more in energy efficiency as a way to relieve stresses on a system that can turn prices chaotic very quickly. The fundamental notion that it does not make sense to rely solely on spot markets however well constructed and efficient to manage the resource risks and the portfolio needs of diversified systems is a proposition that I think holds up well for both the electric and gas industries.

I am not trying to re-introduce utility-based integrated resource planning under a new label of utility-based portfolio

management. My point is that these utility responsibilities never really went away. For example, during the California crisis when the spot prices tripled and then tripled again, it was not helpful to tell customers that it was not the utility's problem. Our core challenge is to examine the constraints and incentives associated with this crucial responsibility and to look for best practices and avoidable pitfalls.

Portfolio management as I describe it is wholly compatible with robust, competitive wholesale markets, which in fact enhance the capacity of portfolio managers to deliver good results for their customers. This is not state socialism. Although if we do not do it better, the advocates of state socialism will be emboldened, wholly inappropriately, in my view.

Question: Almost by definition, an IRP looks only at investments that can be funded solely or only from a utility's customers. What happens if you want to bring in wind and you need large infrastructure development, but the beneficiaries would extend far beyond your customers?

Response: One benefit of having regional institutions is to develop more credible and publicly defensible justifications for the enhancements that are needed to benefit the entire system, and then create the base of support for system-wide cost recovery.

Speaker Three

I learned long ago that most economic decisions, if not all, made by politicians tend to be political decisions. Three years ago, my company announced a creative, aggressive strategy to upgrade our generation and distribution system in a reliable, cost-effective, environmentally responsible manner. The state in which we primarily operate is experiencing small

but relentless annual growth. Meeting that demand requires base load plants that operate continuously; intermediate load plants that operate primarily on weekdays and peaking plants that operate at times of peak load and often in a particular season. Any new generation must complement our existing portfolio and strengthen our overall efficiency, reliability and environmental performance. We must consider fuel supply, price, transportation, environmental impact and public opinion in deciding what plants to propose.

We believe that our balanced fuel portfolio is a built-in hedge against the market fluctuations in one or more resources at a given time. Since it is always difficult to predict markets over the long term, a diverse fuel mix also protects against supply disruptions and vulnerabilities and lessens the negative impacts on customers and shareholders.

We targeted 5 percent of our electricity to come from renewables by 2011, about double that required by state law. We have applied for a 20-year license renewal of our nuclear facility. From a supply standpoint, a blend of renewables and coal makes the most sense for future base load generation. We think that natural gas use for power generation should be limited to peaking and intermediate load generation; the huge quantities of gas needed by base load plants would drive up prices and therefore costs for other uses competing for limited resources and infrastructure. We are also investing \$4.3 billion over the next decade to meet environmental obligations, using advanced technologies to reduce emissions.

By 2010, our capacity will be approximately 14 percent nuclear, 51 percent coal; 32 percent natural gas and oil and 3-4 percent renewables. On an energy basis, it will be 23 percent nuclear, 63 percent coal, 10 percent natural gas and almost 5 percent renewables.

Sound strategic planning is essential in determining resource allocation and utilization needs and the implementation of a balanced energy portfolio. The planning should be done at the utility level, and not as part of some centrally driven master plan. With their customer, regulator and supplier contacts, utilities are uniquely positioned and qualified to develop a comprehensive portfolio. Market-based companies should also be allowed to submit proposals. Clearly, the market for fuels plays a role, but fuel selection and portfolio management cannot be based on the market alone. Effective planning is important, as is weighing the range of alternative and applying the utility's unique knowledge of the area served to determine the fuels that best suit the area's needs in a reliable, cost effective and environmentally responsible manner.

Question: Are energy efficiency and DSM part of your planning process?

Response: Yes. The state administers the conservation programs. As the price of electricity increases and more conservation becomes cost effective, it should be the first supply source that you harvest.

Speaker Four

Which customers really want someone else to choose fuel? What are the customer segments? Obviously this depends on whether your state has customer choice. It is clear that there is a fairly large segment in customer choice states – especially the larger industrials – that do not want anyone to choose their fuel. If you impose it on them, they will find ways around that either politically or by self-generating. We must also remember that as we go along, will the people who make the choices bear the costs if they are wrong? What levels do people have to force fuel choice, especially in the financial markets? We

are not choosing between market imperfections and some other perfect system; we are choosing among imperfections.

As has been pointed out, there is little debate about mid-merit and peaking plants: it's difficult to imagine what else to do besides natural gas. And DSM is particularly effective for peaking load. The debate is really about the base load plants that run up to 4,000-5,000 hours or more when the issue is between coal and gas volatility.

I note that it is important to be cautious about coal and gas volatility. There is little volatility in coal prices because generally when such plants are built there is a specific mine that services the plant, a long-term contract and a transportation contract. Boilers are usually designed for specific types of coal, and it is physically difficult or it de-rates the boiler to switch to other types of coal. The only reason we seem to view gas as being more volatile than coal is we are comparing a spot market in gas that does not exist for coal because almost all coal is sold on long-term contracts.

Gas plants are modular and essentially come in \$150-175 million chunks –two combustion turbines and the steam turbine and the recovery steam generator. You order it, it shows up, and your construction period is less than two years. But the people who want to build coal want a super-critical plant because of its engineering efficiencies and especially its load-following characteristics. Such a plant does not come in sizes less than 800 MW – and 800 MW is \$1.2 billion. They are subject to construction issues, they take longer to build and typically tend to induce more social and political furor.

Only one super-critical plant has been constructed in the US in the past 15 years. Several of the firms that used to build them no longer have the staff who are

used to supervising large-scale construction. Therefore construction risk – an issue we have not had for a decade – may come back in a very unpleasant way.

If you are a 5-billion-dollar utility, how do you build a 1.2-1.5-billion-dollar coal plant? Another issue is regulatory pre-approval. You might have a contract approved by a commission or a state legislature, but you may not get the price you want when the plant is finally completed. The ratings agencies have been very clear with companies about expenditures for things that are not dedicated to rate base. This is why they love substations. Huge amounts of capital expenditures coming onto utility balance sheets will be very difficult to withstand. They have to come with a regulatory compact wrapped around them. In my view, the size of the financing will constrain the ability of the industry to really generate huge amounts of coal plants.

If something is too big for one utility, why not have two or three companies do it? It is almost impossible to run a plant effectively with other partners, especially when some of them are in very different financial situations. It happens rarely. It can happen with a gas plant, though because if the rotor breaks, you just call GE. But running a big coal plant is far more complex.

In conclusion, it is not clear to me who will ante up when they guess wrong. If gas returns to 2 dollars, I think you will see people wandering off the system, especially in customer choice states. If it does not, I am concerned about small companies being able to afford a state-of-the-art, super-critical coal plant.

Question: Why does AFUDC no longer work?

Response: It is only effective to the extent to which people who invest money in the

company believe it. The idea of going forward without pre-approval and simply booking AFUDC is not going to happen.

Question: Is it feasible that there could be a large plant with two or three co-owners that satisfies EDGAR to the extent that approval is needed from FERC?

Response: An example is a company that owns the bulk of a plant that has at least two other partners with rights to ownership. To make it a non-federal asset, the plant there is no PPA: the plant is leased. One affiliate builds it and the utility affiliate leases and operates it for the 25 years of the contract. The other partners have the right to purchase its power. The builder – the non-utility entity – has no rights to the power. This eliminates the need for any type of rigorous federal approval.

Response: When you sign any lengthy contract, the rating agencies take the power purchase contract and turn it into a dead equivalent. The problem for the seller is that you do not want to reduce the credit rating of your customer because your ability to finance the plant will dwindle. If you are planning an 800-1,000 MW coal plant where it could be a substantial fraction of the load, you may suddenly find yourself with non-investment grade customers.

Comment: Individual developers of nuclear plants have decided that at a certain point, it is better to have one of the three or four large nuclear aggregators to participate. I do not see anything wrong with a model in which those entities ultimately are the developers and operators of the coal plants and the asset remains in the asset base of an individual utility.

Response: I do not disagree, but we have not had construction price risk for a decade, and I think we will see some. I do not believe it will be of the character or

magnitude of the nuclear construction program that had the capacity to ruin the industry and generated bankruptcies.

Question: Is a vertically integrated industry's credit its customer base and the flow-through mechanism, and not its balance sheet? During the California crisis, PG&E had complete credit on the gas side because it had a pass-through mechanism, and no credit on the electric side because it did not.

Response: Practically speaking, an entity with less than 40 percent equity will not be investment grade. It does not help if it cannot recover the costs as they pass through.

Response: The credit ought to be based on the customers and the pass-through mechanism. But absent legislation, rating agencies do not look it that way because regulators change their minds and a commission is not usually bound by the acts of a prior one. For example, when the delay in a plant is becoming chronic and the costs are mounting five years from now, the newer commission may decide that its predecessor made the wrong decision and rating agencies will look at this as debt.

Question: Why pursue LNG if there is sufficient domestic gas? Can you explain the differences in opinion about the adequacy of natural gas?

Response: LNG coming into the US is good because it creates stability in the world markets and creates a freer flow of the commodity. It will be very competitive when more re-gasification facilities are built here and elsewhere. The domestic market will no longer determine the value of the commodity. I do not think there is a problem with 1,300 TCF of recoverable reserves. We have a situation of adjusting between supply and demand because of the reduction in adding reserves a few years ago and we are now catching up. I

do not think that gas should be reserved only for peaking capability. It is a good fuel on a combined cycle basis especially because of the efficiency of today's modern equipment and because of the environmental benefits.

Comment: The scariest thing about the California crisis was that PG&E came within about two weeks of having to depressurize its distribution system. Nobody would sell gas to it. It was finally able to secure gas when the CPUC authorized it to pledge its accounts receivable against gas purchases. Recently, the CPUC renewed that authority. Even though it is coming out of bankruptcy, PG&E's credit situation still has not stabilized to the point where it can reliably buy gas at decent prices.

Comment: Slightly more aggressive targets are being set for energy efficiency for California's utilities on the basis of determining that if the resources are more cost-effective, it is better to use them before investing in anything that is more expensive.

Comment: I think that the high targets that are being set are unachievable.

Question: Is it likely that LSEs will be able to make long-term investments, either contract or utility-owned generation, to meet resource adequacy requirements?

Response: In a customer choice state an LSE's major asset is the load it serves. If you are the incumbent utility and face the possibility that 20 percent of your customers could disappear or go off your system, what are your obligations and how far in advance do you plan? The answer is that either no one can leave, or they must leave promptly.

Response: Or do not go long for everything. Your diversified portfolio is in the spot market, some in short-term purchases and some of it can be long.

Comment: How do you force people to pay for fuel diversity when it is out of the money? If you do not think they are willing to pay for it in a market that shows them the economics, why should we take comfort it would be supported politically, because we are still dealing with the aftereffects of what turned out to be incorrect decisions in hindsight.

Comment: As long as something as critical as energy is decided on a political basis, in the sort run we will continue to struggle to get where we need to be. Today 25 percent of the world's population has no access to electricity. By 2050, half will have no access. We tend to consume the lion's share of all of the energy produced. We will continue to have problems until we begin to consider the implications of a policy that does not advance energy into developing nations and become more efficient in our uses.

Comment: There is a major movement to impose renewable portfolio standards on LSEs, including retail and wholesale suppliers, which I think is a Band-Aid solution to get some fuel diversity.

Response: It is not clear that large C&I customers, left to their own devices, would not choose diversity. If these customers are only choosing three-year contracts, then the LSE ends up choosing for them because it has to select the most competitive portfolio as those contracts role over.

Comment: An LSE still must meet the RPS requirement set by the government policies in which it does business. The better you are at optimizing your ability to find that 10 percent RPS, the cheaper you can offer the power as you go forward.

Comment: There may be ways to integrate more of a resource portfolio management model into systems with choice, recognizing that there is a durable load

that stays with the hometown utility that is perhaps not served best through 1-3-year contracts. I think that ways could be found that do not suppress the ability of the larger customers to opt out and try something else.

Response: Even for the mass market, you want the wholesale power supply to be procured competitively and to be a mix of short-and long-term contracts.

Question: What is between total market choice and total regulatory choice that makes good public policy?

Response: The middle ground is good resource portfolio management with good incentives provided by state regulators. What is wrong with natural gas right now is the exposure of too much of the public and the industrial base to extraordinary price volatility. State regulators must recognize that the entire country is riding the spot market in gas and that it is time to have a more diverse base and more hedging.

Response: Both politically and economically, industrial customers have choices that are unavailable to other customer classes. If they make the wrong choice, they bear the burden of their mistakes. However, it may be that you will not be able to let hospitals, for example, bear the risk of their decisions because if they make the risk and it goes wrong, you have to bail them out.

Comment: Because the financial community feels bitten by bad investments in the electric sector, it makes it very difficult to find the large capital necessary for base load generation from an alternative fuel, unless it is an emergency-build situation. Then the only option will be quick build of natural gas and the cycle is perpetuated. So the choices that are made are much larger than just what is available for me to buy, if the only choice is what the market offers. There is a lot of

aging infrastructure that must be replaced at some point because we are not charging people nearly the replacement cost of power. However, the massive over-investments have been a real boon to the electric customer.

Response: IPPs and others saw an opportunity to take a new technology into a market that was opened up by the 1992 legislation and they deployed assets in locations where they thought they could get a good price for their produce. Next time around, regulators ought to charge utilities with making good planning decisions to serve their load and to establish the appropriate margin of reserves. Regulators also ought to establish a fair and transparent system of competitive procurement. Regulators have a role to establish a profit to a utility that chooses the lowest-cost, most reliable product to serve load. Then I think the private sector will begin to invest again. But the big link here is a long-term contract.

Question: Besides the risk of CO₂, are there are major issues for coal?

Response: Technology can remove 80 percent of it from a facility. Gas has more of a problem with fine particulate than coal. Government needs to set the standards that we can meet, not moving targets.

Comment: The correct approach is to get long-term clarity on future targets and timetables for reducing the major emissions and then let industry manage to the lowest-cost solutions. Although there are new coal generation options that may make it easier to remove carbon, the problem is the uncertainty about its future regulation.

Comment: A strong transmission grid could solve many of the issues about planning for fuel diversity and reducing

risk. It is a social good necessary for this country to have a strong energy backbone.

Response: In some ways it may be even more challenging than generation because it is one thing to build a 500 MW plant on 12 acres and another to cross 3,000 miles of the people's land. I suggest that the best contribution utilities can make is to rebuild the distribution system in this country to twenty-first-century standards.

Question: Is planning substantially a geographically specific process? Is so, utilities are in a particularly good position because they can break their service territories into reasonably sized planning units and they understand the values of the people in their communities.

Response: The ideal process is to have everyone in the room or at the same hearing so that a resource plan is developed that is consistent with a state's environmental, commercial and other needs.

Question: Is there a point where we should be concerned that we are too reliant on one source of energy? How much price volatility is society willing to tolerate to rely on the marketplace?

Response: The issue really is how we build a system that is reliable enough to meet the changing circumstances of volatility and customer load. One way is to treat energy much as you do commerce, and build an interstate system for transmission that allows access for multiple suppliers.

Response: Many customers are willing to take volatility risk for lower expected value. Others do not like it. We should not choose what kind of volatility they want. However, it is a different question for residential customers. I find the argument on LNG and national security tenuous. Gas is storable, and while we do have the

OPEC event, the notion of a mercantilist view on energy policy is not benign.

Response: Today, about 20 percent of the country's electrical production is from natural gas. I think it will take a long time to reach 25 or 27 percent. We have contracting mechanisms and hedging mechanisms for the customers who dislike volatility. Natural gas is a little different because it can respond to supply and demand signals quicker than politicians perhaps can make decisions.