

**Harvard Electricity Policy Group
Thirtieth Plenary Session**

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RAPPORTEUR'S SUMMARY*

Session One: Which Way from Here? We Have Seen the Future: It Doesn't Work

The promised benefits of reliance on markets in electricity have simply not materialized. California is Exhibit A. We have witnessed extreme price volatility in the West, shrinking investment in generation and perhaps transmission as well; reliability problems, abusive behavior in the marketplace; widespread financial distress; and a variety of other ills on a scale never seen in North American energy markets. Retail competition has proven to be, by most estimates, a bust. Does planning serve the public interest better than market forces? Will society, or at least politicians, be intolerant of the same level of price volatility that is acceptable in other markets? Are we simply incapable of getting the market design or institutional arrangements correct? Regardless of the reasons, we are clearly in transition to another regime. What will it look like? Can the old monopolies be reassembled? If not, what will the market structure look like? How can state and federal regulatory policies get in sync? What is the vision of the future?

Speaker One

It is clear where FERC wants to go and it is clear, too, that the states either do not want to move ahead with retail competition, or they are moving back. The bad experiences in California and elsewhere have made both politicians and the general public skeptical. If restructuring occurs on any radical basis, it could be extremely risky and disastrous outcomes can occur. Unlike other industries that have restructured, in the electricity industry, if you do not get the

little things right, then bad things can happen.

For example, retail choice for small customers is not working, but I do not think we should give up just yet. It will take time. And if we want to improve the performance of the wholesale market, it probably becomes necessary to ensure that there is retail competition. This is a gamble for policymakers and state politicians, but if we do it right, over time society and consumers will benefit.

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

We are still grappling with how to identify the best-practice institutions that underlie restructuring, like giving the right incentives and breaking down the barriers for transmission expansion. Is it politically feasible to resolve the problems of siting transmission that are interstate in nature and the benefits flow across states. There is debate about finding the balance between markets and governmental intervention. We could have too much intervention, which I think is conceivable in an environment where people are skeptical about markets because of corporate malfeasance and other reasons. Government activities can include market monitoring, implementing codes of conduct to ensure a level playing field; setting prices for transmission and distribution. If government plays a large role, then are we better off? I do not have an answer.

Working out the economic theory and instructing people has become difficult, probably because of the politics. If regulators have not priced correctly over 80 or 90 years, will they do so after restructuring? What happens to the benefits of restructuring if there is no demand responsive pricing or there are incorrect price signals??

At the beginning of the debate, many people may have discounted the role of regulation in making competition work. We said, "Let's get the regulators out because they'll have nothing to do. The market will set prices and do all the other things." Now I think we see the need for continued government intervention in these markets.

People can always make the excuse that there is never a right time to move ahead. Perhaps we underestimated the difficulties of restructuring. Perhaps we felt we should just go ahead, dealing with issues along the way. Perhaps we did not realize the difficulties that arose because of the technical aspects of the industry.

Finally, it is important that restructuring's advocates do empirical studies to show the benefits, and for policymakers to do empirical analyses. Before we go ahead with a policy, there should be some evidence that the results will be favorable.

Speaker Two

The title of this panel is, "It Doesn't Work." I qualify that by saying I think it does not work if done badly, and there are many ways to do that. I will talk about Ontario, some of the lessons I learned there, and then about the future of electricity competition generally.

Ontario Hydro, a Crown-owned monopoly with integrated T&D, was largely nuclear. Mother Hydro as it was called, was a popular family jewel. Almost everybody had someone in the family or knew someone down the street who worked for Hydro. The province also had municipals that were mostly small political fiefdoms.

In 1995, the Ontario government commissioned the Macdonald Committee to gather input about competition. In 1997 the committee released its plan. It recommended breaking Hydro into generation and transmission; privatizing all generation except the province's nuclear plants; creating an independent market operator; turning the Ontario Energy Board into a real regulator; paying off stranded debt with a competition transition charge; and starting both retail and wholesale competition in 2000.

Ontario's government then issued a White Paper that accepted most of the recommendations. It decided not to privatize or break up generation, but to put it all into a single Crown corporation called Ontario Power Generation, or OPG. Private power could compete on the margin for new capacity and OPG might some day sell some of its existing capacity. The White Paper also called for

the consolidation of the municipals – politically difficult – and the creation of a market design committee.

The political justification for these efforts was that the province would be competing with the lower prices in the US and that Ontario consumers needed choice. However, the feeling among the general public and opposition from labor unions made privatization a hot potato. Perhaps it could come later.

The market design committee was a non-expert stakeholder group. Everybody was on it: the new companies that would be formed from Ontario Hydro; large consumers; small-consumer advocates; Enron; IPPs; environmentalists – about 15 people in all. It was chaired by a dean from the University of Toronto. Putnam, Hayes and Bartlett were employed as experts, advisers and staff. The first set of rules was developed in this consensus environment.

The market design consisted of an ex post spot market, no day-ahead market, no capacity market, no LMP initially. The latter was a flaw, but given the process and with Enron fighting it tooth and nail, LMP probably did not stand a chance. Market power mitigation was a master vesting contract with OPG, a bit of a problem for a competitive market when the company owned 95% of the province's generation. In simple terms, Ontario Hydro had been getting 4.3 cents per kWh, which is also what consumers were paying on average. When the weighted average price went above 4.3 cents, OPG paid the difference, multiplied by a quantity, ultimately to consumers. The quantities were based on modeling estimates of what OPG would produce if it were acting as a competitor, given its capacity. In principle, this removed OPG's incentive to drive up the price, but did allow the price to go as high as necessary and to call for new supply when needed.

A new Crown corporation, the Ontario Electricity Finance Corporation, was established to assume all of Ontario Hydro's debt that was estimated to be above what the new commercial companies could service in the competitive market. A competition transition charge was levied on all sales, and the revenue that came in under the market power mitigation agreement to serve the debt and to pay consumers rebates. If it received more than what was needed to service the debt, it was rebated to consumers through a settlement mechanism. The local distribution companies basically passed through the spot price and any rebates they received were paid by retailers. Then consumers paid the retailers whatever the contract agreement was.

There were some perceived and real problems, though. Congestion was not a big one. There were some problems with trading arrangements with the US. Competition was blamed for the T&D charges that went way up. There were some retailer scams. The gridco, Hydro One, ran into some corporate scandals about salaries and expenses.

OPG's biggest problem was restarting some nuclear plants that had been closed. This went over budget and behind schedule. When prices went up from capacity shortages, the provincial government feared another California, and so there was a political reaction.

In November 2002 after the market started, Ontario's new premier froze distribution charges for the munis and rates for all small consumers. Anyone who had paid more than 4.3 cents per kWh at any time since the market opened would get it back from somebody. The provincial government would demand that the federal government stop imposing the GST on electricity, but of course Ontario would continue to pay the excess debt caused by the previous government's

inefficiency and mismanagement and pay for enough new supply to solve the problem. It was never clear how all this would work, but it was clearly the end of the market.

Currently, the situation is that the rate freeze may be extended to large consumers. Hydro One was going to be sold through an IPO, but the sale was cancelled. Boards have been purged of companies and replaced by more politically pliant members. The OEM and the IMO are under pressure to line up and do what the government wants. There are severe financial problems and huge debts piling up.

I think the biggest mistake was keeping the Crown monopolies, particularly OPG. As often happens in restructuring, people who have been running state-owned entities cannot wait to get that million-dollar salary and to start making deals. They run out and do stupid things, and in fact, there was a fair amount of that.

However, hanging over the market for several years are the several thousand MW of basically taxpayer-subsidized new capacity that will come into market any day now, but never actually materialized. It discouraged private investment. So Ontario faces a shortage.

Other mistakes were the lack of room for retailers because of the prices that were fixed by the CTC and the market power mitigation agreement. Retailers were left convincing customers to switch by comparing their energy-only price to the all-in price that consumers paid. When they got their bills, consumers realized they were actually paying a lot more and they felt cheated by the promise of competition.

A problem in many areas is weak political leadership. The politicians believed that if they created a market, they could control Ontario Hydro, but then they could not do

what they needed to change the Crown corporation enough to bring it under control. Political weakness led to keeping the monopolies and a weak regulator. At the first sign of trouble, the politicians just gave up.

Now more generally, the evidence is that restructuring has worked when there is a strong government both driving and leading the process. It took both because a failed system had to be saved from regulators and politicians in Chile, Peru and Argentina. By introducing a market, they were able to insulate the industry from the political process to some extent, and reestablish it. It also worked in the more developed economy in Victoria where union control over the electricity sector was so big.

Restructuring has failed when the market design was entrusted to self-interested parties – I put California in that category – or where political support was weak – I put California and Ontario in that category.

Restructuring has never happened where there was no political will to tackle the monopolies and/or where the existing system is viewed as working well enough – I put Europe, Japan and most of the US in that category.

Restructuring's objective is low-cost, reliable electricity, not competition or markets for their own sakes. The benefits of electricity competition are lower costs due to competitive pressure, discipline of capital markets, less political intervention in economic decisions and better price signals. But you cannot just deregulate electricity and walk away, like you can for other commodities. In the US, the benefits may not be large, where regulation is relatively competent, honest and effective and has produced reasonable service and prices.

Once you begin combining regulation, competition and monopoly, regulation becomes very difficult and you are at least as likely to make big mistakes than just dealing with a monopoly. Costs and risks in the US are significant; you have a state-federal system, special interests and politics that you do not see in other countries. Broadly speaking, SMD is the right answer. I think it will probably spread slowly and unsurely, given the resistance. Maybe the best future is wholesale competition to supply LDC monopolies, which then sell to small consumers under prudent regulation of their purchasing.

Question: Why did Enron oppose LMP in Ontario?

Response: It was a strong opponent of centralized markets of any kind, but particularly LMP.

Question: How do you define “works?”

Response: Restructuring worked in situations where there was an identified problem that was more or less solved. Arguably, it worked in the UK and in Australia in the sense that the market is working: prices are at least no higher than they would have been otherwise, and maybe even lower. My loose definition of “works” is that it is not necessarily the most efficient outcome, but the lights stay on.

Speaker Three

As a commissioner, I am obligated by statute to promote retail competition and open access in my state. I also took an oath of office. I believe that the questions posed by this panel depend upon the environment in which we find ourselves when answering. I have tried for a long time to solve some of the problems with markets and electricity. I have not been persuaded by what others have said about

the solutions, but I am still open to being educated.

The first question, does planning serve the public interest better than markets? Certainly, there are problems in trying to get a planning regime that actually produces results with which we can be comfortable. I think planning gives an opportunity to do things that markets will not, but it is not a guarantee.

Will the public tolerate price volatility? No. Are we incapable of getting it right? Where we can, humans are likely to make mistakes. The electric industry is exquisitely vulnerable to what appear to be small mistakes, but have huge impacts. In every state I have looked at, there is always one company that seems to be doing something right. But the few competitive suppliers out there are consolidating or withdrawing. Green Mountain Power just abandoned Connecticut. At the state level we hear, “You’ve got to give us headroom. Your POLR rates, default rates, standard offers and transition service rates are too low.” I want to reply, “I don’t want deferrals either, but I don’t want to just build in headroom for you.” But they are right – it costs between half a penny and a penny-and-a-half per kWh to market and operate a back office and it is killing them.

Most of the savings that customers have seen I characterize as transfers from one group of customers to another. For example, New Hampshire got about \$150-200 million out of PSNH in the form of write-offs after 5 years and a massive federal lawsuit. Other places were getting 100% straight of cost recovery; California got 120% cost recovery, and it still did not keep them out of bankruptcy. There were also price-cap fights.

You are now starting to see a consumer backlash against LMP. In some places like the northeast, it is becoming clear that prices are going up and retail consumers

will not be happy. In fairness to the pro-competition movement, some of the problems are temporary. Eventually, capacity will be built. It will be possible to get capital. Traders will eventually recover. Metering prices will come down and it will be possible to expand the scope of realtime pricing without the high costs we have had in the past. And over time, we will improve market rules.

Some of the problems could be resolved if we had the political will; we could cut a deal with FERC so that people know where to go in the future. Conceivably, the feds could win outright, but I do not think they will. If the states win outright, I think things will stay where they are, but that is not enough to solve the problems.

Transmission will be a monopoly because it does not make sense to have duplicate poles and wires. We can try to do generation on a merchant basis. Many would like to see a programmatic response to get more demand – I like market ways of doing that – but it still involves government intervention. I do not think anyone has figured out how to make complementary resources work together. To the extent that it is a monopoly, you end up getting the public involved, and that slows down everything because of due process.

Booms and busts are endemic to this industry and there is no way to get around them. We live with that in some other industries, like Boeing and shipyards. Although you might not call them government subsidies, they have to rely on portfolio buyers to keep them going through the bust periods. That leads to the question: who will manage my portfolio as a small consumer? Who will provide the stability through boom and bust? Who will manage my portfolio so that I have reliability?

The era of Margaret Thatcher is dead, but on the other hand, if there is no crisis,

states will stay the course. They have too much invested in moving to an alternative. They do remember stranded costs – that is what opened them to the idea in the first place. The public is still suspicious. We do not trust government to manage these things, yet the federal government is pushing hard.

What will happen? SMD is not a huge issue in the northeast, because we have already done most of it, except for LMP and capacity planning. The south and west will not because nothing is in it for them. PUHCA will be around, but it will still not be enforced. There will be no further erosion of vertical integration, and the debates will slowly turn to POLR and safety nets – where the “Who’s going to manage my portfolio” question will be answered. I do not think that the alternative of public power as a hedge will grow. We will see at least one transco get off the ground and we will continue to have fights over standard offer.

We are in transition to a new regime. Can the old monopolies be reassembled? In some places they never were disassembled, and they will gradually reassemble. If not for retail in New England, the mid-Atlantic and the Midwest, the big customers will have some choice, but the market will not want to serve small customers because it is too risky and there is no margin in it. There will be bumpy wholesale competition until the crisis of capacity. Then I do not have any real predictions.

Question: If there is an excess supply of generators in today’s market and people cannot get money to invest in generators, is that good news or bad?

Response: If we operate on a boom-bust cycle, it is good. Capital is not stupid. One advantage of planning used to be that you would always be building a little bit too much, but over a smoother time period, and try not to have as much boom and

bust. However, I remember in the mid-1980s when people complained that there was not enough generation. So planners do not always get it right, either. I wish there was money going into hedges now because I think we will have a capacity crunch and we need to look ahead. Most of the efforts to get ICAP in place are only thinking ahead three years.

Speaker Four

I will concentrate mostly on California. I began working for a California utility in the mid-1960's when there was a consensus about the state's infrastructure. We were building a university system that would be the envy of the world and a great highway system because people knew where they wanted to go.

Now fast-forward to 2003. The state budget is a disaster. Tremendously high electricity prices and high taxes are coming. Most important, there is no consensus about infrastructure – its form; is it really pro-growth; who is in charge. These days, California is not unusual in this respect.

With regard to the industry, in 1993 there was no consensus about this experiment. It was simply decided, for political purposes, that we should privatize risk-taking at the generation level -- let the market do it. In my mind, if restructuring made any sense at all, it was in that regard. In a nutshell, did things work? I have to say that seldom has so much been spent for so little so far.

Nonetheless, the reason it was adopted in California was that the previous process was broken. In 1992-93, there were 35% reserve margins. Supply-side interests had captured the political process and were trying to get utilities to buy still more capacity, based upon the environmental externality of reducing air emissions from existing plants. One observer commented that it might have been better to first get

the wholesale market in shape in terms of competition, instead of both wholesale and retail.

This is a highly politicized industry, unlike natural gas. I think there were some problems with the previous regulatory environment. The incentives to operate plants perfectly in terms of efficiency were absent. Getting rid of regulatory costs if we went to competition never occurred. There has not yet been a lot of privatization of risk-taking; instead it seems to me that we have had a lot of socialization. We do not have low cost to capital now. When we tried to disentangle the vertically integrated utilities, we discovered that there were indeed vertical economies between transmission and generation.

Now in California, there are three utilities with different views and there is no consensus among them, which is somewhat unusual. There are high-priced contracts with the Department of Water Resources. Some municipalization is starting off. I am concerned that the utilities do not have a reasonably stable retail base to support financial investments in new generation, and neither do the IPPs. The latter will need a long-term contract – at least 10 years – in order to get financed. Who will they sign with? No one will lend the IPPs money if they think that the utilities lack the stable retail basis that makes them a good counterparty.

A tremendous amount of generation has been built in the Phoenix, Arizona area. I do not think there is enough transmission to bring that power in. Will our industrial customers move there instead? Somehow, we have to quickly re-institute investor confidence, especially in generation. To do that we must clarify the role of the public sector, like the California Power Authority.

I do not see that transmission to relieve congestion will be sited too many times on

a competitive basis. We must think carefully about the role of competition. We have thought grandiosely about setting up big market structures, much of which seems to be like textbook thinking about competition's role. We need to study how to mix competition with the inherent planning and public-purpose aspect of the industry. I agree that it is difficult to meld these aspects together, but the best that we can get out of competition in my mind is socialization of risk. I do not think we will depoliticize the resource planning process to any degree. The operating efficiencies that come out of competition are not huge when you go beyond the shutdown decision.

Discussion

Question: You say that IPPs will not invest or speculate on contracts, but they have in the past. Has the perception changed?

Response: I do not say forever, but the IPP environment now is that the conventional equity markets and banks need a power contract in order to loan money to build a merchant plant.

Question: Do you advocate a return to cost-of-service regulation for wholesale transactions? Is the real issue whether we will have well-functioning markets?

Response: Some arbitrary accommodation must be made between the merchant generators who would not necessarily be at cost-of-service regulation, and the other generators who would be. I recommend half to the vertically integrated utilities and half to the IPPs. I do not know the percentages, but you make an arbitrary split.

Comment: If you return to cost-of-service regulation for wholesale, in effect you say that there is no way the markets could be competitive and that we have to impose

price caps for regulation. I agree that our objective should be to improve the markets' structure and performance so they are competitive and can produce benefits for consumers. This is the challenge for FERC and others.

Comment: If you do price caps, you also have to do price floors implicitly. It is likely that there will be no competitive markets in the south and west; they will be somewhat competitive in the northeast and only tolerable if we are not in a capacity constraint.

Comment: A state should be able to build generation under a cost-of-service regime. I see things working best if it is a matter of local control at the state level, but facilitated with a good interstate wholesale market.

Comment: I can imagine a world in which LSEs and regulated LDC load-serving entities that may or may not be vertically integrated have a responsibility to serve their customers under a combination of contracts and perhaps some ownership. Contracts would be regulated on a prudence basis, and if they could not get them in the market in certain situations, entities could build or contract with someone. That has some aspects of cost-of-service regulation. I believe that many problems in markets around the world have been caused by trying to force retail access, retail competition. Resource adequacy and other problems arise because there are entities that lack a customer base. If you back off, at least for small customers, it makes things work better.

Comment: As to how well the old markets worked, the New York Power Pool was in serious trouble because there was so much pressure under the regulated model. It did not allow 100% cost pass-through for fuel clauses. There was so much non-compliance with the old rules, which only worked reasonably well if you got all your

money back, that people were already figuring out how to design a better system. The southeast has a competitive wholesale market, but with very bad market architecture. I believe we need to focus on what is needed to fix where we are now.

Response: I am not saying that wholesale is unimportant but what needs to be clarified in California are some big picture things such as who is the retail base; what is the security of that base; and what is the commercial model for investing during the next 5 years. We could have a totally static wholesale market design right now, but that is not the big driver of future disasters in California.

Response: As an economist, I would focus on transmission pricing, and then pricing for distribution service, assuming you have a competitive or quasi-competitive wholesale market and that the pricing will be basically okay. I agree that for the time being, we should forget about retail access for small customers. And unless we deal with the problem of transmission siting, it will greatly undermine any benefits that would come from restructuring.

Response: Even if you lack active retail competition in many of these markets, you will have the LDCs and generators not knowing what the future will be. I think that creates many of the problems in investment.

Response: A continuing and important problem is that we have a federal system of government, but regional markets. Some people in New England believe that FERC's push to have such huge regions is counterproductive, has wasted time and has slowed down the process of figuring out how to get the markets to work right. You cannot get it right in a federal system unless you have a manageable set of institutions. As a region, New England has family disagreements, but of course the states should take care of their own. All politics is local and that is a state

regulator's job. Ideally, we would develop workable regional institutions that could make binding decisions about resource adequacy, procurement, siting and so forth. I think the boldest thing is to get an interstate compact with a governance structure, but I do not see how we will get the political will to do that now. If we have a capacity crunch, maybe we will. FERC is too remote; it cannot deal with this from Washington. The power needs to reside closer to the people, but we do not have a way of doing that.

Comment: We do not have strong, political leadership because we lack a set of clear ideas from people who identify the three or four next steps to take.

Comment: One productive step is to recognize that the economics of commodity retailing for mass-market customers are ugly.

Response: I am not sure how retail access for small customers hinders industry restructuring. In most cases customers are staying with their local utility. In fact, retail access is just ineffective.

Response: If there is no protection and no clarity of rules, utilities do not know whether to sign contracts for a set number of years. They do not know whether they will get cost recovery. As a supplier the fact that this is happening by default gives me no comfort.

Response: While we have not figured out what to do about this institutionally, we are sitting on the fact that retail has been a bust and we are riding on six-month, one-year, three-year contracts. This time will end within five years and we are not ready.

Response: State commissions must give guidance to the utilities in terms of their hedging strategies. That does not mean that commissions should approve all of the costs associated with a prospective utility

action because commissions generally are hesitant to approve, and rightly so, I think.

Question: What role could competitive bidding play, particularly if we fall back more to reliance on vertically integrated utilities?

Response: Competitive bidding makes sense if you fall back onto a model in which the LDC-LSE has a firm customer base and has to prudently get supplies for that base.

Response: IPPs are able to lean on the balance sheet of the utility and leverage up and they always convince people that they are considerably cheaper, simply because of that. At issue, also, is the politicalization of the next resource. We do not want it to be all gas. How do we value the resource diversification of building a coal plant? What do you do in terms of risk for future emissions policies?

Comment: A unique set of circumstances allowed reasonable competitive designs in four countries. Argentina is an example, but two weeks ago a poll there showed that 60% of the people wanted to re-nationalize the infrastructure. I wonder whether any reform is possible in this highly politicized environment.

Response: If you believe in democracy, everyone should have a say in the decision and the consensus should be consistent with the will of the majority. Designing national policy at this point in time probably means that you have a lot of safeguards, caveats and conditions that would be inconsistent with promoting competitive markets. I do not agree with everything that FERC is doing, but they are saying, "If we want to move ahead with restructuring, we have to do it because the states and Congress will not." In the gas industry FERC took the initiative to promote competition and restructuring.

Response: In any other modern capitalist industry, supply is never the problem. In electricity, many more things have to come together in order to add supply to dampen prices. All of them have environmental and land-use impacts. I do not think you can or should get the politics out. Instead you have to manage the politics. I do not think you can manage them from the federal government and obviously in most cases, the states are too small a unit.

Response: There must be broad, indicative planning over a ten- or twenty-year period. We need to make the utility a decently incentivized agent to achieve our goals.

Comment: Regional governance would include a charter and a constitution in which the values are set out, and decisions about whether to include environmental values. Because many of the values will clash, at least in individual cases, the decision-makers must be both independent from the money flow – to the extent that they must try to moderate clashing interests – and knowledgeable. State governors would appoint people, probably with proportionality, not strictly by population, but with deference to the state's share in the power pool. State regulators have made their share of mistakes, but they are supposed to be independent of the money flow and knowledgeable.

Comment: From my perspective as a system operator, there are five key features of SMD that have generated little or no discussion: open access; security-constrained economic dispatch; locational pricing; demand response; and infrastructure development. Which of these does SMD not address constructively?

Response: SMD is probably the answer to make the wholesale market work. SMD's main problems have to do with the

resource adequacy and the market power aspects, and both of these are complicated by the lack of contracts – which in turn are exacerbated by retail competition. SMD does not deal very well with the infrastructure issue, although it tries by establishing the institutions.

Response: SMD is a good approach. I believe that open access is necessary to make wholesale markets competitive. LMP seems to be the best theoretical method to manage congestion. It is fine to try to encourage consumers to conserve and they benefit by the price, but offering them additional incentives can lead to some problems. I think that SMD does not totally address infrastructure development, instead relying somewhat on the market and planning to handle that issue.

Response: The issue of open access is only secondarily important for the purpose of competition, but it is very important for the purpose of transmission-dependent LSEs. That raises this question: Do we want a system that encourages people to site generation near load, and for areas to take responsibility for meeting their localized resource requirements, or do we want the benefits of the efficiency of remotely sited load generation and using transmission to get it to load? If you want the first, open access becomes an override over the price signals and the constraints that would otherwise tell you to build locally or to reduce demand. I think LMP will not be politically sustainable. I think we are just throwing money at demand response, rather than figuring out the barriers between customers' loads now and reductions.

Comment: Politicalization is essential for an essential service in a democracy. Yes, low short-term prices are one factor of decision-making, but others are fuel diversity, stable long-term prices, low-income energy burdens, clean air, future supplies. All can be thought of as

economic arguments, albeit difficult to quantify.

Question: Who wins and who loses?

Response: If California does not decide on a particular option and go in that direction, I think consumers will be the losers over the next five years. What is the commercially viable plan to build new generation, if we need it? The problem is that the utilities are sitting ducks. They have sunk capital. If they fail to do what you want, you can always lower the return until the cry uncle.

Response: In New England, consumers are doing fine, but are not being well served by the drift and the failure to look ahead to the crunch.

Response: It is an illusion to divide the world into consumers and producers and others like pension funds. You need to say what happens to the overall efficiency and cost to the economy if you make big mistakes. I have come around to the view that you have to figure out what makes political sense. If small customers knew that on a retail basis, their local LDC was buying power to meet their needs and keeping the prices stable, consumers would not care much about the wholesale market. You could go ahead and get that market right and then in twenty years come back and worry about retail competition.

Response: Utilities will continue to do fine, as long as they do not become involved in wild investments like nuclear.

Question: Can the US have an electric system where different regions do different things?

Response: Absolutely. The economics of transmission are such that it only makes sense to be regionalized.

Response: It is important that the commercial seams be smooth. I think that will support both commerce and reliability. That is easy to say, of course: a problem in the West is the big institutions like Bonneville Power Administration that have their own ideas about how things should be structured. In the next 15-20 years, three different ideas will be put

forward. We ought to work on making commercial transactions seamless among those three entities.

Response: The more standardized the details of the market, the better. But seams are the real issue, more than the detailed inside rule.

Session Two. We Can See the Future: It Is Working.

We are already seeing the benefits of competition in some parts of the country, particularly in the northeast where the market designs have produced reasonably efficient and highly reliable markets. The problems of California and elsewhere are behind us. They were the products of poor market design that will be remedied; abusive practices that will be easier to detect and eliminate in the future; and in some cases, simply bad luck. The changes the industry has undergone are deep and pervasive. We have no choice but to move ahead and complete the reforms. FERC's standard market design proposal, or some variation of it, points to the direction in which we need to proceed. It builds on the changes that have already occurred, and corrects many of the mistakes of the past. The critical task is to create robustly competitive wholesale markets with many opportunities for demand-side bidding to compete with supply side. Can SMD succeed? Is it really possible to ignore the viability of retail competition? Do we need appropriate retail price signals for end users, in order to optimize wholesale markets? Are reserve requirements incompatible with full competition? Aren't reserve requirements and market power mitigation an acknowledgment that we can never rely exclusively on markets to produce adequate supply? What is to be done if society and its politicians are not sufficiently tolerant of price volatility to allow markets to work? What is the vision for the future?

Moderator

Is it in the national interest to have a patchwork of wholesale markets, which we now have, with some functioning well and some poorly? If we know what works well in terms of market structure and design at wholesale, shouldn't we just have the courage to insist that what works well be implemented on a national basis with some modest regional variation? Recently, FERC held a conference on capital availability and why capital has been fleeing from the energy industry. A similar conference held five years ago was on the direction of FERC policy. The message then was that FERC should get

out of the way and let the beauty of the markets work. At the latest conference, the message was that Wall Street wants well-structured, credible, enduring markets; transparency in accounting and in market data; clear and strong market rules; and FERC should structure the markets and oversee and monitor them, to ferret out abuses. Two representatives from Wall Street even argued that when there are proceedings under Section 204 of the Federal Power Act to approve securities, FERC ought to take a close look at why the securities would be issued. Will they be issued for investments that will be in the public interest? FERC has never really taken a hard look at those kinds of

transactions. It has approved almost every request for security issuance that has come before it.

Speaker One

Before I say how the future may look like under SMD or similar, my first message is “the system is currently broken.” To make my point, I will address several issues, the first of which is long-term planning. Now, long-term planning is done utility-by-utility or sub-regional at best. I have sat on many regional planning coordinating committees. You see utilities every year submitting ten-year plans, where very little happens the first year. The planning coordination process is simply hypothetical. It is multi-state, multi-utility, multi-regulator, multi-year, and the list goes on, with little outcome.

The result is that in North America, from 1977-88, transmission capacity growth occurred mostly at the same pace as load growth, or a little better. From 1988-98, it lost ground. The forecast in the 1998-2008 period is even worse.

Some Westerners say that this is an East Coast problem. I say the California crisis did not last long enough to give us enough experience and expose the western infrastructure. In fairness, during that crisis, western state governors and provincial premiers agreed that the region needed an institutional measure to deal with the problem and keep the control in our own hands. They also recognized that the West is an integrated economic region and problems should be addressed as such.

Over the next ten years, the west needs 35,000-40,000 MW of capacity to meet natural growth. Today, there is no transmission long-term firm capacity in the entire system. How will we get it to accommodate the incremental generation capacity and meet growth? Do we build and then wait, or let them come first and

then build? To address the issue, we assumed a number of resources scenarios in the region, ranging from small gas turbines as close to the load as possible to a more colorful resource portfolio. Even when you look at the least-demanding transmission scenario, some projects would have to go through siting processes in two provinces and three states. Other resource scenarios would need even more substantial processes under the current planning structure.

Under the current structure, would generators come in and build the 35,000-40,000 MW? No. Could the utilities do it? Half of them are in severe financial difficulty. Even if they wanted to, they do not have the money. Believe it or not, there are at least four entities with money, waiting to invest in transmission. But they cannot go for a five- or six-year process involving multiple commissions and differing timetables for decisions. One developer, who represents only 600 out of the 35,000-plus MW, has already been in a process for three years. This is the current system that some are trying to protect.

A recent study by the Western Governors Association recognized that planning should be centralized on a regional basis, because the west is a natural market and that is how the planning should be defined. It should be one-stop, multi-state plus federal. It has to have incentive rates and be market-driven. Isn't that what SMD said? If the first was a good initiative, what is wrong with the latter?

The second issue is congestion management. Some say the financial approach or LMP is an East Coast approach that is not good for the west. The western region is limited by technically non-linear phenomena like stability, it is not a thermally based system and it is over-subscribed. It was emotionally attractive for the west to try the physical approach first. But with the special

characteristics stated above, we spent almost two years trying to make it work and it did not. Westerners accepted the financial approach. We stopped calling it LMP. Isn't that what SMD said?

The third issue is pricing. SMD promotes elimination of rate pancaking. The sensitivity to the so-called cost shifting is phenomenal. Is it really cost shifting? By how much? In the west, transmission represents roughly 10% of the total delivered energy cost. The third-party transmission revenue you get from that part is a fraction of that whole transmission. The part at risk is a fraction of the third party's fraction. When you talk about cost shifting, it is fractions times fractions times fractions. While the sensitivity is so high for a potential percent or two in exchange for market efficiency gain, annual increases of orders of magnitude under the current structure are perfectly accepted.

The fourth issue is Canadian participation. Canadian trade is mostly north-south. There is actually much less interaction between Canadian provinces than between provinces and the states. This is why Canadian participation is important. How difficult is it to participate in SMD? At first there was a lot of emotion about sovereignty and other issues. But what is best for all the customers in Canada and the rest of the US? Electricity is just one piece of the economic chain of the continent. Canadians recognize that it is important to be fully involved in the process. They also know that operating responsibility in Canada must be in the hands of a provincial regulated independent utility. After all is said and done in a collaborative market design process, the US side goes to FERC and the Canadian side goes to the Canadian regulator with an identical market design for approval.

Finally, SMD is not about forcing competition in the energy market, but

about creating a coordinated, open, multinational, efficient common carrier of electricity that facilitates the transportation of electricity from low-cost resources to where it is needed. This is simply good public policy. That is how it should be taken; all the rest is just emotion.

Question: Is there no long-term capacity in the west today?

Response: If you want transmission access on a firm basis for long-term – meaning more than a year – you would not find any. If a generator wants to build, there is no long-term firm transmission.

Speaker Two

In order to fix things, you need to understand where you are. I would like to posit that most of the firms, regulators, stakeholders do not actually understand the world they are in right now. Let me start with the regulators because I was one in Queensland, and there is nothing more parochial than Australian regulation. This is a state that purposely built its rail system in a different gauge so it would not be able to trade with the rest of the world.

Regulators face the problem of buying long and selling short. That is no different from what generators and transmission owners face. Their assets will be 30, 40, 50 years long-lived and they are selling into a market when they do not know if their customers will be there the next day. One way to fix this problem is to give them a franchise – a long-term contract. If you are a utility, the biggest thing that you have got to value on your books is your franchise. It has nothing to do with your plant or your wires. But the minute you allow open access, the value of that asset depreciates and you must come up with a new way to manage the risk of buying long and selling short.

Yesterday, I got my electricity bill. I actually read it. It said that I have a customer charge of \$4.05; a delivery charge of \$44.94; a transition charge of \$53.55; and a generation-related component of \$54.37. I was not quite sure about the customer charge. I felt I did not need to read about the delivery charge, plus or minus. What is a transition charge? I turned the bill over and it said, "This charge, which as always been a part of your electric bill, is estimated to end on December 32, 2006." That did not help much. I called some of my friends. Finally I found someone who told me, "That's the stranded asset."

Now if I eliminate the transition charge, my generation-related component could double and still see no impact on my bill. That generation component is directly related to what I do as a customer: who I buy from, how much I use and so forth. In other words, I can hedge that generation component either physically or financially, but I cannot hedge the other side.

I did not know about sump pumps in my basement. They went on and off and I am like, "What's it doing down there?" When the power went off in a heavy rainstorm, I found out. My five children and I started physically hedging our position in the electricity market with buckets because that \$53.55 transition charge was not providing reliability at that point in time. I could get a rebate on that, because I did not use the reliability at that point in time, did I? Or could the utility pay me to use the buckets?

My point is that I cannot hedge two-thirds of my utility bill. Two-thirds of the bill has been decided for me. Was it an efficient decision, the one I would choose in a different set of institutional circumstances? I already had to double-hedge.

The generator's role is to optimize its assets for the best gain of its shareholders. That is how markets work. We can make lots of things work; some will work better than others. But we do not make much headway as long as we set up a game in which one person is right and the other wrong. What we have now is an emphasis largely on the debate, instead of what is best for customers and industry going forward, and what will be best tomorrow. I think SMD goes a long way in focusing that debate. But industry and regulators have much to do in terms of educating ourselves, shareholders and stakeholders.

I think we need to look at the issues differently. In order to do that, we must understand that the world is not the same as the world we were in last year or the year before. Start from the premise that change could be beneficial, as opposed to all change is bad. Obviously, we are in a very dynamic environment. We now have competition in terms of large- and small-scale generation, remote and local. We recognize that one size does not fit all. The politicization of the process is inherently a political topic. Interestingly, in New Zealand and Australia, the definition of the electricity industry as an essential service arose from the governments' desire to control the right of workers to strike. Reliability is a thorn in SMD's side. As a homeowner, I do not need four 9's reliability. We will have pressure to commoditize reliability and it will be difficult to price reactive support.

The economy overall faces international pressures competitively. We need people who want reductions in their bill. New Zealand and Australia are both large exporting countries and it was the exporting sector that drove much of the reforms. In a competitive environment, it is difficult to maintain cross-subsidies. When we lived in a world where nobody moved, businesses lasted 20-30 years and households were much the same, you could cross-subsidize business, residential,

or back and forth. Now, the economy is more transient. Regions, grow, fall, build up again. There is increasing pressure to price or account for environmental externalities.

As a result, I do not think we even have an option of going back or staying where we are. If you think it is political now, wait until water gets into the act. All the pressures that electricity is facing are multiplied in water. And even if we could go back, would it be in the best interests of the customers? I am not sure. I like to argue that the debate is about centralized versus decentralized decision-making. In particular, it is about where the appropriate boundary is between the two.

In the ERCOT process, the grand assumption was, "Let the markets work everywhere, complete decentralization, no rules for the dispatch process" and so on. In a little over a year, AEP received over 600,000 individual command-and-control orders from ERCOT. A market is not working very well when there are 600,000 instances where the coordinator has to step in.

At least now by definition, real-time is where you need centralized decision-making and market design. It is increasingly difficult, if not impossible, for structures based on centralized decision-making to come up with the appropriate outcomes. For example, Australian regulators faced the problem of coming up with appropriate rates of return. Figuring out the cost of capital on an international firm, such as an American utility that had bought utilities in Australia, was unbelievable difficult. One American utility told regulators that its purchase price was determined by its tax situation.

Therefore, I think it is more appropriate and beneficial if we focus on the areas where we can decentralize, let the market work and then that will establish the

boundaries between command and control versus where the market is. By getting the things that we do know right, we keep the lights on with a dispatch process that is transparent, accountable, replicable and auditable. The only way I know to do that is security-constrained, economic dispatch, using LMP. If we do not get real-time right, we set up fictitious arbitrage opportunities and we get incentive incompatibility. We need to align the economics and the physics.

And market participants, Wall Street and everyone else must have confidence in the efficacy of the governance process. This is one way to manage the buy long-sell short problem. If you know the rules can be changed at the drop of a hat, you will include a risk premium. There are many models, but the governance must be efficient.

When you try to figure out accounting systems that were used by trading houses versus regulated entities, FTRs do not rank very high in that debate. There is a disconnect among boards, senior management and the rank and file who are involved in the market operations. It is industry's role to bring them together with politicians and regulators included. I cannot understate the importance of education by industry.

Speaker Three

Do LMPs relieve congestion? They have been used in New York and PJM for four years. There are over 100 million data points to look at – 2,000 points every hour. I have looked through data to analyze the cost of congestion in New York over the past three years, and in Del Marva and PJM. My perspective is that of the transmission owner and the people who own TCCs.

First, there is a general feeling that LMPs add to price volatility. I think that is

debatable because there has always been congestion in the network. But let us assume LMP makes it at least appear more volatile. The complexity, volatility and unpredictability of LMPs make them a poor crystal ball. They are great for hedging, but as a basis for a particular transmission investment, they do not work very well. I have some suggestions about how the market could be designed to utilize them to improve such investment.

LMPs do point to congestion causes, but most of the congestion occurs in fairly isolated places. LMPs are useful for a transmission planner to see what is really causing the problem. LMP is also useful to identify what occurs at different times of the day in different locations and the data can show price volatility from the addition of congestion, compared to other locations. I would rather see shadow prices, the cost or value of relieving a constraint, in addition to LMPs, because it rarely occurs that there is one constraint in the network. Five-plus constraints per hour are common in these markets. Ten or twenty outages are common. Shadow prices are very good at telling you the cost of eliminating the constraint.

It would also be useful to know the amount of load affected. That would really give the market a better signal as to what is serious. The data may show a lot of apparent congestion, but it may only be affecting a few MW of load.

Question: Who calculates the cost, and on what basis, of relieving the constraint?

Response: The security-constrained economic dispatch or unit commitment program.

I always thought congestion would become larger and more frequent as we load up, but it does not work that way. It is just as expensive to relieve congestion at average load. Why does it occur at all load levels? The first reason is frequent

transmission outages. Generation outages tend to skew the flow in the network. Another reason is unit commitment decisions and restrictions. All the units bidding in have minimums, ramp rates, minimum run times, and other complications, and these tend to cause congestion at medium-load levels, even where there are no particular outages occurring. Bidding patterns and generation location are another reason. There is always fear that those nasty bidders will create congestion, but I do not see it in the actual information.

Cost does not follow hours very well at all. You could eliminate all of the normal planning congestion that you run into, and three-quarters of the time, you would have congestion anyway. Tackling it will be a difficult chore. Predicting LMPs is difficult because outages, maintenance and unit commitment occur at all load levels.

Do CRRs, TCCs, FTRs, FCRs – whatever alphabet you use – make good investments? New York's famous central-east interface basically divides the state one-third/two-thirds and is certainly the most frequently mentioned cause of congestion in the state. In 2000, the total congestion costs were about \$785 million. It went up because of the outage at the Indian Point nuclear plant. In 2001, not much happened. Do you make an investment based on a water main leak in New York City that caused a cable to be out of service for three months? I do not think so.

Why spend money on new transmission? It is either an entry fee, an insurance policy or an investment – the only reasons to spend money on transmission other than reliability. Do LMPs inform or motivate such investment? No. Giving someone a CRR, you spend \$20 million to eliminate congestion. Now you own, say, 200 MW of CRRs. The congestion difference is zero: 200 times zero is zero. I just spent

\$20 million and I received zero and in fact, am probably helping my competitors. Instead, I buy a hedge, but it does not motivate investment. Even if I get something for it, the volatility and unpredictability of congestion is very difficult to take to the bank. It does not have to be a 300-mile-long line; it could be putting another transformer in a substation. An entrepreneur does not do this, because where is the payback?

With some good thinking, I hope we create ways to use LMPs to motivate where investment should occur, both in transmission and generation. Maybe if we came up with a third clearinghouse marketplace, we could smooth out some of the LMP volatility. Often, it is a very small amount of load that generation can fix. Perhaps we could have a market that LSEs could tap into, and fold that into the security constraint unit commitment and dispatch and thus eliminate a lot of the LMP volatility. Maybe we could set aside some capability in flowgates that belong to you and are not used in calculating LMP. There are some set-asides already – transmission reliability margin, CBM. We need to have LMPs really make an investment decision, as opposed to just a hedging decision.

Question: Are you saying that LMPs are not a good predictor for transmission investment because you put money in and there is nothing there?

Response: Yes, not only year to year, but hour by hour, day by day. It is difficult to hang your hat on them.

Comment: Before the market opened in New Zealand, the DC tie between the south and north islands was constrained almost all the time because they were just looking at the thermal constraints. But LMPs in New Zealand actually included reserve prices. When the market opened, the DC tie was largely constrained because the price of reserve in the market

was so high. It affected investment decisions to either increase or run another pole on the DC tie. As a result of the market, they decided not to increase the investment.

Question: Do you suggest that we withhold some transmission system capacity that we might grant in rights to ensure that flowgates are available?

Response: Speaking from a merchant transmission perspective, if a company makes an investment in transmission, that piece of investment should belong to them. Otherwise, you just help out your competitors. If you improve the system such that you have eliminated some congestion, you should be compensated either by ROR regulation or you have to own a piece of the system that belongs to you, so it would be withheld.

Speaker Four

FERC got to SMD because of zonal markets, sequential markets and settlement systems that failed. This market design is not an intellectual or theoretical process. It is well founded in economic theory and it has empirical backing. There are no known technical problems to the implementation of LMP. There has never been an instance where we can actually look at a problem that somebody presents and argue that SMD does not work. At least in my reading, SMD has significant opportunities for state and regional variations: resource adequacy requirements; CRR; calculation of access fees; the way you do dynamic mitigation. But I think in some cases FERC's SMD NOPR was over-read because some people wanted to interpret it as an intrusion on state prerogatives.

The cost-of-service nostalgia – the legacy of Samuel Insull – is something that people think of fondly. We have already seen that there was a huge stranded cost.

The nuclear plants we built are not worth 15% of their book value. It turned out that the fossil fuel plants we built were worth about 200% of their book value. Now, some people declare that to be a success, but it is a complete failure of the cost-of-service regulatory regime where book value is supposed to reflect the value. I challenge even the best cost-of-service people to calculate the cost-of-service rate for an IPP that does not come in with a long-term contract.

All markets have rules and sometimes we need to change them. Mitigation is very important, but it can be error-prone, so we have to watch how we do it. In some sense, because FERC is there to protect them, people do not want to do long-term contracting, or think it is unnecessary. If you say that we will not enforce 205 and 206, my guess is that the market would adjust fairly quickly, but industry would not like that.

Market design is really important when the market is tight. If there is excess capacity, almost any market design will do. At least in theory, it is important that the market be efficient and competitive when the bidding is truthful. There are market designs where that is not the case, and the problem is that truthful bidding is often not in the interests of the parties. Good information systems obviously are important, but I think trying to do market power mitigation before the fact is a waste of time.

The important issue about resource adequacy is whether we will count demand-side bidding. FERC will do nothing more than say what it did in its NOPR: "If you're short in the realtime market, expect to pay high prices; if you're long, expect to get the high prices." It says nothing about who pays it. And you can completely avoid these things with CfDs. Consequently the people who are short see a higher price, not consumers. If you are long, you are happy.

The reality is that mitigation must be politically tuned. You have to pay attention when prices are high. Mitigation is the rationale in my opinion, for FERC not having to be heavily involved in the forward bilateral markets. My favorite choice is what I call dynamic mitigation. After the bids are submitted in the real-time and day-ahead markets, you estimate whether there has been an attempt to exercise market power. Under certain triggers, you change the bids. Basically, if unit by unit there is a problem, we will correct it. Dynamic mitigation is the least error-prone and requires the fewest assumptions and guesses. In New York it has been triggered very infrequently. It requires less information. For example, a rough calculation of marginal cost and the value of lost load are probably all you need. You do not need to estimate what capital cost is amortized over the life of a plant, or to regulate the forward market or its marketers. However, hydro and energy-limited resources are a problem to be dealt with especially in terms of mitigation.

If you want a retail access program, have an entity that procures power on behalf of those who choose not to go someplace else. If an entity chooses to leave, you pick up a slice of that program and it moves with them. It is an entitlement. If the entity returns, the entitlement starts over. With an SMD market, if you are over or under your entitlement, you are automatically put in the spot market to pick up the adjustment. This way, you can do long-term planning. It does not force anybody to the spot market.

My position on the meters issue is that customers should be required to have either meters or curtailment equipment. If you do not have meters, curtailment becomes an externality because you cannot black out entities that have not bought forward in certain markets. It is not the cost of the meter; it is the cost of the curtailment system that is not being considered.

The debate is just starting about transmission expansion under an independent RTO. The argument in the 1970s was whether generation could be competitive. Vertically integrated utilities said no because it caused problems. One utility even argued that independent generation would cause death. Almost uniformly, ITCs have said the only way they can properly operate is if they are a franchised monopoly. Ask them if there is any role for merchant transmission and they say it just messes up the system. They also say that RFPs for new transmission investment are too difficult, but they probably would do it anyhow.

In summary you need: good market design; good information; compatible incentives; interaction between the markets and the physics that makes sense; and a hope that the market approach can replace the planning approach or at least significant elements of it, in the near future.

Question: Have you looked at Alberta, Australia, New Zealand and Argentina where single settlement markets have worked pretty well?

Response: In every case in the US, the single settlement went to multiple settlements and everybody was happier as a result, as far as I know.

Question: Could you talk more about metering?

Response: If you cause an externality and it could be that the system could collapse and there could be blackouts, we lack the technology to black out the people who are not participating in the market. Some argue that when the market goes short, you should either be required to put in real-time metering on your system or the ability to be curtailed. I think the issue may be the kinds of costs incurred: the real-time metering cost or the cost of installing a switch that allows us to curtail

you, like we used to do or probably still do on air conditioners.

Question: What is the best way to mitigate market power?

Response: An overly simplistic response to a definition of market power is withholding from the market at higher than marginal cost. That definition may stifle investment. It becomes a more complicated event or definition if you add the investment decisions into the process, because you can get some anomalous results. It is situational and a simplistic definition may not serve us very well.

Comment: Determining who owes what three years after the fact is a bad policy. We ought to have a system where prices are mitigated more on a real-time basis if the bids appear to be out of line. Essentially that is what SMD proposes.

Response: In California there are no day-ahead and real-time markets that are amenable to marginal cost bidding. Telling you how to do market power mitigation when there is no SMD market is difficult; there is no simple way to do it.

Comment: I agree that AMP in New York is invoked infrequently. Partly, this is because people know it is there, but also it is quite difficult to try to game this market, if you will, when LMPs are so volatile.

Comment: Some people are so afraid of AMP that they are altering their bids. Whatever price comes in, they do not show up because they are afraid of being AMP'ed. We have to be careful in terms of anything we do, whether there is any interjection. We have to realize the unintended consequences in terms of behavior.

Comment: I disagree with the assertion that the chaos in the west would have happened anyway but for the kinds of

changes that occurred. I think everyone would agree that a poorly designed and manipulated market structure in California, FERC's abandonment of its duty to ensure just and reasonable wholesale prices and its creation of price arbitrage opportunities by capping prices in California in 2000 but not outside the west, caused more carnage in areas outside of the west as a result. When FERC imposed its must-run order in June 2001, 10,000 MW of capacity came back into the market and shortly thereafter, prices collapsed. Now we are back to the status quo ante in the wholesale market generally in pricing. In retrospect the carnage is horrific. Rates in Idaho are up 48%; Montana 23%; Nevada, 44%; Oregon, 35%; Washington, 48%; California, 27%. Other western states will be 25-50%. A typical family in the state of Washington has lost about \$450 of real income from this grand experiment. The DOE's national grid study estimates that efficient wholesale trade in the west would yield consumer benefits of about \$8.6 billion, and that benefits that have occurred to date from existing bilateral trade facilitated by Order 888 – which was a good idea – are about \$8.3 billion.

Response: A faulty structure also happened in Alberta. The province's day-ahead financial non-binding market means that day-ahead schedules are jokes because anyone can submit anything. Prices went through the roof before California did, and then California's own problems reflected throughout the region. We allowed bits and pieces from the entire region to develop their own markets in different ways, and even then put them under independent entities. We ended up with independent inefficiencies instead of inefficiencies. When prices were high, there was either transmission that was severely constrained from areas where the price was very low and it did not go to where it was, or people made arbitrary decisions by withholding. The fact is that the structure was wrong. You cannot

isolate yourself by saying, "You restructure your own way, but I will not." Imagine if the entire region is effectively one control area. Then the one percent reserve in California did not have to be when the Northwest had 30%.

Response: It is significant that our prices are back to where they were once FERC put its must-run order into place.

Question: If the resource adequacy requirement means that if you are short and prices are high in the spot market, you have to pay them, why do you need the requirement?

Response: In some sense it may be a misnomer that it is a resource adequacy requirement. I do not make excuses for what happened in the west, but the only people who paid those high prices were the people who were short. Whether or not there was market power in those high prices, somehow they had not planned properly for their native load. FERC asked people to pay attention and to think about going long. It wanted them to report their net position to the commission. There is one sentence in FERC's SMD NOPR that says 12% reserve margin, but I do not think it was to chisel anything in stone.

Question: Do you need 25-35% reserves in order to discipline the market to marginal cost?

Response: No.

Question: There are two competing models of transmission expansion in FERC's SMD NOPR. One is a centralized planning model in which the RTO looks at congestion within its boundaries and decides where to build transmission, based on the location of the congestion. The other is to let the market decide by awarding congestion rights to those who build transmission. I agree that may be insufficient, but the problem with the centralized model is that any investment in

transmission will affect the value of generation throughout the system. Some generators will be hurt while others will have an advantage. I think all sorts of fights will develop when you start to centralize the planning of transmission in an LMP world.

Response: With centralized planning, you set up a zero sum game and the modes of opposing new transmission lines become more sophisticated. You will have more than under-funded environmental groups resisting a line because there will be winners and losers. That is why I believe we need a market-driven means, despite the difficulties in doing it to avoid the zero-sum game.

Response: We do not yet have a good vocabulary to discuss transmission withholding. Technically, it is not difficult to put it in the ISO dispatch models, although it could be computationally more difficult.

Response: Centralized planning means there is one entity in the region responsible for facilitating the analysis and identifying bottlenecks, possible scenarios of resources and funding mechanisms. It is the ultimate in market-driven if you do it on a largely regional basis.

Question: Under centralized planning, any decision will have positive and negative impacts in the region. Is this just shifting money around?

Response: One RTO or one entity is facilitating a centralized process, not making the decisions.

Question: Is the concern about the limitations of trying to predict behavior a factor that limits FERC's ability to review merger applications effectively?

Response: You do not want to build up concentration in the markets. Doing

market power mitigation or market-based rate analysis before the fact requires too many assumptions and too much information that will change; maybe it is not worth the effort. AMP or dynamic mitigation before the market is realized is almost in real-time because it would be done after the bids are submitted. Unfortunately, in markets without SMD, mitigation is much more difficult, bordering on impossible.

Comment: There were 11-12 good-sized generators in California. It did not seem concentrated, yet in real-time when there were shortages, that last increment of generation seemed to have market power and could set a market-clearing price that was above the price in a well-functioning market. We need real-time mitigation measures that can avoid two- or three-year-old refund cases.

Comment: A slight outage of either generation or transmission can change the configuration of a network. Or when there is a hot summer and a low hydro year in a system dominated by hydro, and the demand side is not participating in the market, there can be unbelievably low concentrations and it is very easy to exercise market power.

Comment: There are complex seams issues. In many cases, the owners of facilities and their customers must deal with the economics of managing the loop flows when they are not causing them. I think it is poorly understood that getting into an LMP market will largely move these issues off the table.

Response: SMD should relieve some of these problems. But if you impose an LMP-based model on something the size of the eastern interconnection, you will be buried in data and will get no information. Flowgate modeling and control will help on the seams issues.

Question: If we do not control mergers and acquisitions, do we end up with no competitors and we deregulate the system with no competitors?

Response: If your market design favors large players, such as large portfolios that do not have the balancing problems of the smaller entities, then you should expect all the problems that you get with large players.

Question: Do you advocate stronger antitrust?

Response: I think there should be a merger policy that favors low concentration, but that alone does not solve the problem. Even a highly divested market will not be free of market power because of weather and network typology issues.

Response: The biggest interference with the free market is over-concentration. I am not sure that we have reached the right balance in the past decade. If we rely totally on the market to get to the cheapest price, we can get there, but at the expense of reliability and investments.

Question: Will FERC allow regional flexibility for CRRs?

Response: I prefer that the states and regions deal with CRR allocation. I am not sure that FERC can do as good a job as the states, if they can agree.

Question: What alternative market mechanisms to provide appropriate incentives for transmission could take the place of LMP?

Response: I prefer using LMPs to identify persistent problems. Too often, LMPs are used as a basis for accounting and accounts resolution. LMPs are more of an information source than anything else.

Comment: A private transmission company wants to build transmission based on a private generation company that has generation. The valuable resource only needs the connection, but the siting issue is a nightmare. If you facilitate a centralized process to find the cheapest resources and where they should go, and you get the right corridors in place based on those inputs – one of which might be LMP – then you have a healthy transmission planning process.

Question: My clients are LSEs that will be contracting long in party to comply with the resource adequacy requirement. The theory is that if you mitigate the day-ahead and real-time markets, then the other markets will be disciplined. But I am concerned because of the requirement to contract forward.

Response: I have not seen much evidence that people are issuing RFPs for three-, five- or seven-year contracts and that the prices they get back are exhibiting market power. A company may respond with a high price as a reflection of the risk and uncertainty in the market.

Comment: I am concerned about the risk being shifted to LSEs, such as the uncertainty about transmission risk, and that over time, the number of competitors will diminish. FERC must show that it has this under control as a political matter.

Question: Are there barriers to entry in the markets where the RFPs are issued? FERC cannot order people to build generation assets.

Response: FERC has dockets pending for market-based rate authority for many suppliers. It is obligated to ensure that they have no market power if they will be charging market-based rates.

Response: FERC plans to respond to the dockets.

Session Three. Regulated Utilities and Unregulated Losses

Among the financial casualties of today's energy markets are the unregulated affiliates of regulated utilities. The losses sustained by some of the affiliates are sufficiently high that regulators in several jurisdictions have initiated inquiries. The theory of the unregulated affiliates, of course, is that regulated customers of the company have no entitlement to any profits earned by the affiliates, and are similarly insulated from the risks associated with unregulated investments. Is that bargain sustainable? Can the utility companies themselves be sufficiently ring fenced to protect consumers or to protect their unregulated profits? Perhaps the ring fence will suffice to prevent the flow of cross subsidies from the regulated to the unregulated affiliates, but will the problems of the affiliates impair the flow of capital and its costs to the regulated company? Should regulators put restrictions on the ability of regulated companies to invest in unregulated activities? If the flow of capital is impaired or its costs driven up, what protections should be put in place to guard consumers?

Speaker One

People have studied this issue, at least since the 1980s, with the problems at Pinnacle West. Some of the generic concerns that regulators have include any major impacts on the parent, such as providing an incentive to divert resources from the affiliate to the parent, thus reducing quality of service, or the amount of equity infusions. Regulators may be presented with a Hobson's choice. If the regulated utility has a significant financial difficulty because of the parent's actions, what happens in the rate-making process? Most companies seeking authority to go into a diversified area will say, "You can penalize me on the rate-making side by giving me an imputed cost of capital." In fact, that may not work because it continues to exacerbate the utility's situation. The rapid decline of the generating and marketing sides began with Enron's bankruptcy. This is so recent that the true impacts may not be seen for the next few years.

To study near-term impacts, we looked at the financial data from the parent and the regulated utility; net income; cash flow; dividends; debt equity ratios; ratings and analyses from agencies and stock analysts; and states' regulatory decisions and investigations. We divided companies into

the categories of: marketers and generators with regulated subsidiaries (AES, Dynegy, Enron); utilities that act as a flat company and engage directly in unregulated activities (Aquila, Westar); a mix of registered and exempt holding companies (Constellation and PSE&G).

As of September 30, 2002, the equity ratio of AES dropped from 35 to 30 percent and its bond ratings declined from double B to single B. Two years ago it acquired the parent of Indianapolis Power and Light. Since 2000, the parent has dividended to AES almost a billion dollars in dividends and distributions. Its capital structure now has a negative equity balance. One could say that the parent is significantly leveraged. Its bond ratings have dropped from double A to double B, well below investment grade.

One problem may have been the lack of jurisdiction. Indiana law does not allow for jurisdiction of the acquisition of holding companies by another holding company. Now there is a debate in the Indiana legislature, and I understand that Indiana will be given jurisdiction over the acquisition of holding companies.

After Dynegy acquired Illinois Power, its ratings dropped from triple B to single B in 2000. However, Illinois Power's

dividends have been in line with its earnings. Its common equity ratio actually increased slightly. Its bond ratings fell from triple B to single B and its third quarter 10-Q stated that it is having problems because of its parent's financial difficulties. In December 2002 it issued \$550 million of debt at 11.8 percent. At that point in time, the debt for an investment grade utility would have been around 7.5 percent. The real problem is that when it spun off its generation, it took an unsecured note of \$2.3 billion back from Villanova, the direct parent at the time. It now has a huge mismatch between the net utility plant and its capitalization. It is seeking regulatory approval to sell \$180 million of transmission assets to pay down debt.

The Illinois Restructuring Act requires no approval for the acquisition of an electric utility, but it does for gas. IP had a gas operation. When approving Dynegy's acquisition, the Illinois Commerce Commission did say that the cost of capital would actually decline. Subsequently, it approved a netting agreement and has restricted the payment of dividends. That restriction, however, appears to have been driven by the bondholders that came in in December 2002.

Portland General Electric has maintained an investment grade rating. I think the reason is that when Enron acquired it, the Oregon Public Utility Commission put on some stringent restrictions.

Aquila, a flat utility, saw its assets grow from \$1 billion to about \$12 billion over a decade. The rapidity of its decline is worthy of note. In 2001, its ROE was 11.7. In February 2002 its annual report stated, "Our credit ratings are investment grade; we're going to maintain them." In January 2003, it is well below investment grade. Two-thirds of its projected earnings were to come from its merchant and risk management activities and international

work. It has written off just about everything and is now returning to its core business. Missouri, Kansas and Minnesota are all investigating – after the fact.

Westar, another flat utility, did not invest in generation and marketing, but in home security protection. It has had steady losses, with its common equity ratio down to 17.8. The Kansas commission is investigating.

AEP just wrote off another billion dollars on top of its half-billion-dollar write-off earlier. So far in 2003, its loss is \$519 billion. What is interesting is that eight or ten months ago, the Ohio Public Utilities Commission put some restrictions on AEP. Remember that the SEC in allowing a registered holding company to invest overseas or to receive EWG status asked the states for comments. Ohio, in a sense, qualified its report back to the SEC and put restrictions on the company. The restrictions were adopted. Ohio opened an investigation on the creditworthiness and financial integrity of all of the state's utilities. Most came back with a "just say no" response – no, we do not need any further investigation." AEP responded that the restrictions put on it should be applicable to all Ohio utilities and that the PUC should evaluate each company's risk management policies and procedures. I think that regulators should look at such policies and procedures.

Allegheny, a registered holding company bought a very large marketing company from Merrill Lynch about a year ago. It is in litigation. It still has not filed a third-quarter 2002 10-Q. Its equity ratio is now at 30 percent; its bond ratings have declined to double B. News reports suggest that various Ohio commissions are looking at Allegheny, but we have not found any formal investigation.

The write-off of Xcel's subsidiary, NRG, resulted in a \$1.8 billion loss for the period ending September 2002. Its ratio is

well below the SEC guideline of 30 percent. Its rating are below investment grade. The reason its state subsidiaries have not suffered the same fate may be that the Minnesota Public Utilities Commission regulates the capital structure of Northern States Power and one of its stringent restrictions includes maintaining a 43 to 53 percent equity ratio. Minnesota did open an investigation. In response, NSP and Xcel agreed, among other things, to a rate freeze until 2006 and encumbering no Minnesota property other than for an SP.

PSE&G is an exempt holding company. It has had some write-offs but is well capitalized. Since September 2002 it has issued a billion dollars in equity. The bond-rating agencies rate its subsidiary A-rated. The state regulatory review in 1992 put a few things in place that I think made a difference. The board of the electric utility's subsidiary must have at least a majority of board members different from the unregulated subsidiary; the board must certify that the investments do not harm the utility; and there is a restriction on the amount that can be invested in unregulated activities.

A few of my observations are that a flat structure where the utility is the holding company is difficult. If the unregulated activities have a financial problem, it goes right to the bottom line of the operating utility. A well-capitalized parent and affiliate can withstand the write-off of reasonably sized unregulated investments. A utility CEO said recently, "Thank God for regulators. They can protect us from ourselves." I think it is partly true that some state regulators can play an important role.

One thing that comes through loud and clear is the speed at which these markets can turn. For example, three years ago, Edison International bought two plants in England for two billion dollars. A year ago, it sold them to AEP for \$980 million

and took a write-off of a billion dollars. The Wall Street Journal has reported that AEP in turn may write that down to zero. This is not Enron smoke and mirrors contracts and the like – these are hard physical assets. We have seen this with Aquila. In February 2002 it said, "We're going to earn a lot of money." In September: "We've lost a lot of money."

The Hobson's choice for regulators is real. What do you do with Aquila, whose interest rates have now gone up to 14-15 percent? If you say no to the recovery of its costs, it is a bankruptcy. And many impacts from the unregulated activities are outside their own service territories. What happens to companies that spun off generation to unregulated affiliates that are now selling to the affiliated distribution company at state-approved rates? When competition truly hits and those unregulated affiliates have to sell on the open market, will they suffer the same consequences as the investments made throughout the country and globally?

Speaker Two

Over the last few years, I have advised state regulators about the risks associated with non-utility investments, analyzing the preparedness of state regulation at the statutory and staffing levels and the political preparedness of state regulators to address these issues. I have concluded that investment in non-utility businesses is a game of brinkmanship that regulators are ill equipped to play. The regulators' job is to protect consumers, not to protect utilities from themselves. Of course a utility would expect to earn high on the upside and then be protected from itself on the downside. The inability of regulation to steer between these two extremes makes me feel that the policy here is clear: "Just say no to the non-utility investments."

My four topics are: the generic form of the industry's transactions; problems with the types of transactions seen; the quality of regulatory efforts to date; some weaknesses at the statutory level and in the appointments process.

There are eight types of transactions seen: acquisition by utilities of non-utility affiliates; new cash investments in existing non-utility affiliates; refinancing debt associated with utility businesses; refinancing debt associated with non-utility businesses; transfer of utility functions to affiliated companies; sales of non-utility affiliates to unrelated companies; joint ventures among utilities, non-utility affiliates and unrelated companies.

Westar is an example of how a single company can manage to do all of these and do them quite poorly. It is a holding company with a utility within it. It also owns non-utility businesses. Westar invested in Protection One, a worldwide subsidiary involved in home security alarm systems, and other businesses. In the name of separation, Westar planned what it called a rights offering and a spinoff. Step one of the rights offering was to separate non-utility debt from non-utility equity. The result would have been that the \$1.8 billion debt associated with the non-utility businesses would sit on the books of the utility, giving the utility a negative equity and the non-utility an equity-only capital structure.

You have negative equity when your capital structure consists primarily of financing non-utility businesses. This set-up was done contractually: if a single guy at the top writes the contracts and tells the two parties to sign them because they both work for him, you can get contracts that do unusual things.

Then you spin off the non-utility businesses to the shareholders, which of course would win a very high market price

because who does not want to be a shareholder in a company that is 100% equity? Even if it were not doing so well, the company would find a way to get back on its feet.

To make this two-year story short, now the utility has been commanded to sell off, or somehow raise funds, to reduce the huge debt associated with the non-utility business that sits on its books. In approximately 18 months, it must either sell off the non-utility businesses or stop dividend payments. Westar must also reverse the inter-affiliate transactions that led to the misallocation of debt and equity between the two parts of the company.

Regulators should not have Hobson's choices, nor should they make them. When Westar complained about having to cut its dividend payments, the simple answer was, "That's your choice, not ours." It will not suffer because the Kansas commission will set the cost of capital at the hypothetical appropriate level, rather than the level that the utility wants. Part of the problem is a failure of shareholder democracy. My guess is that Westar's most typical shareholder is a retired person in Kansas who really plans on having a conservative investment. If the majority shareholders want this type of diversification, they can do it on their own.

Westar's management had no experience in the utility business, but was brought from Wall Street for the express purpose of trying to inflate the company's value by associating it with non-utility businesses. It was their dream, not the shareholders'. Maybe shareholder democracy will work better next time around.

Some call this current state a standoff. I call it regulators issuing orders, and utilities finding some way to obey them, or else. While there is really no joy in Kansas, people are blaming management, not the regulators. In other words, the

present management knows enough not to blame over-regulation, excessive review or micro-management. They know this is a problem of their own creation and that is progress.

The problem with transactions that I most emphasize is the question of issuing utility debt to finance non-utility businesses. You do not want non-utility business investments that will raise the risk level for the entire company. If the equity cost and debt cost rise, you can respond at rate-case time, but that is a crude tool. One of the limits is that we do not want to put these companies out of business for the simple reason that we have no alternatives to them, except in a retail competition era, and that has yet to emerge. The notion, “You fall if you fail” is not really a strategy.

The Hobson’s choice for regulators is, “Maybe we really should allow more utility debt to be issues,” which is a little like feeding more alcohol to someone who says they cannot live without it. It does not solve the problem, and you have to ask, how you let it get to this point. Aquila, which committed the sin historically of issuing utility debt to finance non-utility businesses, is now visiting western states like Colorado. The trade press has reported that Colorado’s regulators were going to take the company’s request seriously. It is bothersome that simply saying, “No, there aren’t two sides to this question” has not yet occurred to Colorado’s commissioners or staff.

Aquila claims that the Kansas regulators do not have advance review authority over the issuance of debt. It told regulators, “We cannot separate the debt of the non-utility businesses from the debt of the utility businesses because all of the debt is in the utility business.” Although all of the utility assets were not collateral for the non-utility loans, the indenture agreements say that there is a default if there is a

movement of assets from the holding company into the utility. You, too, would write your indentures that way if you were a lender and wanted maximum protection in this context. The utility argues that the regulators are not giving it enough time.

From a regulatory perspective, there is no justification for someone to enter a non-utility market without having earned its way, instead of using the leveraging of the utility business. There is much effort wasted to clean it up afterward.

There are some preventative techniques. Wisconsin’s statute limits the total of non-utility investment that can sit in the holding company, or in the entire family. There are reporting requirements and detection techniques, but they work only if you have detectors and a staff-to-dollar-of-investment ratio that is not laughable.

That brings us to after-the-fact problem-solving techniques, which are often subject to intense legal assault. For example, Protection One – 85% owned by Westar and 15% owned by real people – told Kansas regulators they have no jurisdiction to order a termination of some of the affiliates’ contracts.

“Ostrich techniques” are always a favorite of regulators. This technique is applied when a company makes its initial request to create a non-utility business. The request is usually coupled with how important it is to be competitive; create career ladders for employees and establish a more hospitable business environment within a state. There is the “Don’t do this again or I’ll clobber you” variation that is usually an assent to whatever has gone wrong, a suggestion that it not occur again in its exact form and not within the term of office of the regulators who issue the decision. Accommodationist techniques work things out ahead of time with regulators, utilities and legislators, to reduce opposition. They are usually associated with a rate freeze during a cost-

declining era in which the freeze matches the term of office of the incumbent regulators.

Some of the weaknesses in the regulatory infrastructure include too much regulatory focus on non-utility businesses, almost none of which is effective. For example, if a utility's financings are subject to state regulation, they are exempt from Section 204 of the Federal Power Act. FERC ordered in the Aquila case a year ago that the issuance of utility debt for the express purposes of non-utility businesses is not a violation of Section 204, even though the section requires the financings to be consistent with the public interest and requires them to be for the purpose of utility financing. I say this is just an unlawful view of the statute.

Pinnacle West, the holding company of Arizona Public Service had invested in S&Ls, which failed in the 1980s. To satisfy federal requirements to bail out the depositors, the company borrowed \$350 million from the insurance industry. Its only asset was 100% of the stock in Arizona Public Service, so it was pledged as collateral. Arizona's regulators believed that would ring a bell at the SEC and pleaded for a revocation of Pinnacle West's exemption under PUHCA. Instead, the SEC's attitude was as though it were the fault of the regulators, not the fault of the SEC.

State statutes vary from non-existent to moderately comprehensive, like the one in Wisconsin that is now under attack and pending in the Seventh Circuit Court. Right now, it is difficult to get a bill through a legislature unless it is a deregulation of utilities bill, even with the events we have in Kansas.

Finally, the regulatory appointment process has little to do with the skills necessary to regulate this industry. Most people are not really trained. That does not mean they are corrupt or inherently

ineffective, but it does mean that people are conservative. In this business, conservative means accommodating, rather than limiting the risks.

Speaker Three

The utilities complain that in a deregulated environment they are being forced into a situation where they get the lower of cost or market. However, to operate in an increasingly competitive and deregulated market you must allow utilities to do different things. If the economic downturn has occurred in a completely regulated environment with no unregulated generation assets, utility ratepayers would still be suffering. When the economy goes south, so do demand projections and you have too much generation supply. Anyone in this business for a substantial period has seen lots of fights about whether utilities had prudently built their generating assets because they actually believed the projections of demand out into the future.

Competition is critical to the efficient operations of a utility. If the only existing competition is cross-selling into another's service territory, the entities are not making substantial inroads into either the generation or transmission business. Where do you find the people who will compete with unregulated assets? The answer is the utility affiliates. Utilities have the expertise. The companies as a whole are in the business. My point is that you do need to have some deregulated or unregulated affiliate utility operation. You also need a certain amount of regulation in order to prevent abuses; you will never be fully deregulated.

FERC's code of conduct has a few principal aspects. A utility and its affiliates must operate separately. Entities with market-based rate authority cannot share market information unless they do so by some publicly available information dissemination process like an EBB. If a

utility sells non-power goods and services to the affiliate, it must do so at the higher of cost or market. Non-power goods and services sold by the affiliate to the utility must be priced at no higher than market. If the utility brokers, or the affiliate and the utility have joint brokering of energy, the utility's assets must be offered first. Note that some state commissions impose similar restrictions on affiliate relationships, although the restrictions vary in effectiveness.

Utilities have asked FERC to help them implement this code of conduct. That has not happened. Some utilities have found themselves in situations where they believed market information exchanges might actually enhance protections to ratepayers and they have been unable to do that. There has been some impairment to the coordination of risk management between the regulated and unregulated businesses, which can leave companies as a whole more open to financial risk.

The SEC requires affiliate transactions to occur at cost. This rule in conjunction with FERC rules sometimes result in transactions at the lower of cost or market. That is not a game utilities should play. States have also imposed rules on affiliate transactions with respect to wholesale power sales that are directly preempted by the Federal Power Act and can conflict with FERC orders.

FERC proposed to prohibit utility participation in cash management arrangements unless the utility had a minimum proprietary cash balance, a capital balance of 30\$ and both the utility and its parent had investment grade credit ratings. Among other complaints, utilities said that these rules conflicted with SEC rules about public holding companies and also with some states' utility requirements. According to industry, FERC had not established a legal or factual basis for its proposal.

I am not saying that utilities should have unfettered discretion to do whatever they want with their affiliates, but we should take a rational approach to make sure that everyone benefits.

Remember, though, that there is no substitute for good utility management. You get better management if utilities and their affiliates engage in a broader range of activities. I think that the quality of management has increased substantially in part because of deregulation, increased competition and the ability to move companies into unregulated businesses.

What is the realm of the appropriate? There are six key factors. To begin, state commissions should have active control of disposition or acquisition of utility assets. They must be able to require that the utility and its unregulated businesses keep separate books and records and separate debt and preferred stock ratings. There must be control over dividend payments to affiliates. Utilities in states with such rules have not been terribly hurt by any downgrades on their non-regulated business affiliates.

Capped rates are an effective way to ensure that utilities are not hurt if there is a downturn. FERC or state commissions may want to establish guidelines on utilities lending money to affiliates. If you comply, there should be a rebuttable presumption that what you have done is prudent, even if things go south at some point. Traditional prudence allowances can protect ratepayers from bad decisions by management, as long as this is not used as a political football.

Commissions can adjust ROEs to offset increased costs related to depressed credit ratings. The utility can have its cost of capital pro forma back to a stand-alone utility level if the affiliate is causing problems.

Yes, we need regulation, but let us not go overboard.

Question: Does FERC lack statutory authority for its cash sweeps rule? Is establishing a rebuttal of presumption that compliance with guidelines on lending money between affiliates is appropriate a part of the rule?

Response: I have not thought much about whether FERC can do that. I think state commissions can do it more readily.

Question: Why do you say that utility affiliates are the natural choice to inject competition into the industry?

Response: If it is debatable that we need competition on the retail level, we have decided we need it on the wholesale level. If you want more competition in generation, someone has to build it, other than the utilities. If you restrict the affiliates, you will not have competition. It would also be good to have completely independent entities coming into the business.

Question: Did you mean to equate the old days of excess capacity in a regulated environment with the situation of Aquila today?

Response: You do not want an Aquila situation. You do not want unregulated businesses dragging utilities into bankruptcy.

Question: Who cares if the regulated rates of return were not high enough to finance utility or unregulated investments?

Response: In a deregulating environment, utilities were under great pressure to find other things to do with their money, in order to protect shareholder interests. You do that through non-utility affiliates, which I think is a natural result of deregulation.

Speaker Four

The activities in affiliate companies can negatively affect the utility company. State commissions can take actions to reduce these negative effects, but they cannot eliminate all of them. I think this problem will worsen as holding company structures become more complex, and particularly if PUHCA is repealed. There is no single structure that protects utilities from the problems associated with the affiliates.

In 1997, Enron bought Portland General Electric, Oregon's largest utility. FERC approved the purchase without significant ring-fencing conditions. The SEC approved the sale with minor changes – the principal one being that Enron had to register as an Oregon company. After a long process in which a great deal of political pressure was put on the Oregon commission and the state legislature, the PUC approved the following ring-fencing conditions.

PGE must maintain an equity ratio of 48% or higher. It must maintain its own separate long-term debt ratings and preferred stock ratings. It must give notice if it plans on any dividends, particularly for extraordinary dividends, or for any raid on the retained earnings.

Oregon's PUC has access to books and records, and there is more frequent reporting of the details of affiliated interest transactions. There is a prohibition on charges from Enron to PGE without commission authorization. There are separate trading floors for Enron and PGE; this was very important during the California crisis.

Another ring-fencing by the Oregon commission occurred in 1999 when Scottish Power acquired PacifiCorp, which was on the market because it was financially weakened by its efforts to

diversify. PacifiCorp had bought a retail utility in Australia and it had made a big effort to acquire the British holdings that TXU won eventually. Since TXU has had to write down those assets, Oregon regulators are not tangled up in that mess, in addition to everything else. The provisions are similar to PGE: no mixing of the companies; availability of books and records (important because Scottish Power is in Glasgow); and maintaining a common equity ratio. One difference is that the parent's effect on the utility is not taken into account when there is a rate-of-return decision.

After regulators approve an acquisition and the combined company is operating, they can take post-ring-fencing actions. Standard & Poor's suggested the "golden share" mechanism. S&P worried that Enron would take PGE into bankruptcy in order to raid its assets. One share of one dollar par value of junior preferred stock holds the right to allow PGE to enter into voluntary bankruptcy, unless there is a regulatory consensus. For a small fee, you transfer the share out of the company to a third party like a securities company. S&P now rates PGE as a stand-alone company at triple-B plus. Interestingly, the assets of Enron's other non-utility affiliates were pledged to Enron only a few weeks before the bankruptcy filing in exchange for a promissory note that is now worthless.

There have been some negative effects of the Enron bankruptcy for PGE. Lenders have sought additional security for debts that otherwise would be unsecured. PGE has been paying higher interest rates than it would have otherwise. At this time, its customers do not, because of a rate case in 2001.

Other commissions have tried to stave off problems, but they are all after-the-fact actions. Minnesota tried to protect itself from NRG-Xcel by prohibiting encumbrance of Northern States Power's properties in the state and tried to prohibit

utility loans to the affiliates. It set new service quality standards so that NSP's service quality cannot be allowed to deteriorate. Arizona allowed a \$125 million loan from Arizona Public Service to Pinnacle West, and more may be on the way. North and South Carolina jointly audited Duke's non-regulated power activities. As a compromise, Duke agreed to a \$25 million payment to ratepayers.

It is interesting that we are in a period when the economy is in recession and utility investments look good. When the economy is booming, the investment community starts saying, "These poor utilities. They aren't earning enough. They need to act like other capitalist entrepreneurial companies." So the utilities invest in unregulated power affiliates or home security operations. PacifiCorp invested in coal mining and utilities out of the country. PEG invested a lot in real estate.

I do not know that these actions were taken purely to enhance the value of the company. To me, when the rest of the economy is on a go-go basis, the utility business seems boring and its executives start heading off, trying to act like entrepreneurs. My goal is to get the companies back to the widows and orphans kind of security that people are happy to invest in, and to get a secure rate of return in good times and bad.

Question: From an operational view, how can credit ratings be separated?

Response: Although the holding company owners own the stock of these companies, their debt is their own, and they issue their own debt in the marketplace. Oregon has said it does not want the mingling of the debt between the parent and the affiliate.

Discussion

Question: What is the objection to using the lower of cost or market by regulators to deal with a utility's relationships with its affiliates?

Response: First, federal and state rules on inter-affiliate transactions may differ. The SEC requires affiliate transactions to take place at cost. FERC's rule says that the utility's transaction should occur at the higher of cost or market when the utility sells to the affiliate, and not above market when the utility buys from the affiliate. When stacked together, you get the lower of cost or market. The Supreme Court has sided with the SEC. FERC then said, "When you come to us for a merger approval, it will be our rules or we set a hearing." Utilities then have to figure out how to satisfy both the SEC and FERC, and it does not work as well as it might. I do not necessarily think that lower of cost or market is the right answer. When a utility sells to an affiliate, you want it to sell at market if market is higher than cost, so the affiliates does not get a subsidy. When the affiliate sells to the utility, I do not see why it should have to collect only cost and give the utility a subsidy. We should make the two entities operate as closely to the way they would if they were unaffiliated, by setting prices at market, but not allowing the utility to sell at below its cost.

Comment: There are two rules, depending on your direction. When the sale is from the utility to the non-utility, it is the higher of cost or market. When the sale is from the non-utility to the utility it is the lower. My understanding of the reason for the two rules is that when the utility sells to the non-utility, it is using resources whose economic risk has been borne by the ratepayers. They are assets or operating costs whose recovery is generally guaranteed through rate making. Because the economic risk falls on them, the economic benefits should go to them also so that you always have symmetry of burden and benefit of risk and reward.

State regulators argue that it should be the lower of cost or market when a utility affiliate sells back to the utility because if the utility needs to provide a service to its customers, it ought to do the service on its own. That is why the utility receives a monopoly. If the utility is providing the service on its own, then the cost associated with that service would be in rates, and thus charged to the ratepayers at cost. If it involved capital, there would be a return on that. By allowing the affiliate to provide the service, you are allowing it to charge a market price above cost. In effect, you have outsourced a service that a prudent utility should be able to do internally, and you siphon from the ratepayers something that appears to be profit in the affiliate's books, but is simply a transfer of utility functions.

Question: You made the distinction between the old days of excess capacity and the financial ramifications in an economic downturn and an Aquila situation, which you would want to prevent. How do you do this before the fact?

Response: Set up the rules ahead of time, live with them, and nobody second-guesses after the fact. I think that utilities are often whipsawed by regulatory second-guessing if things tend to go south. Have limitations or state commission oversight on when the utilities can lend money to affiliates. Also have state regulation over non-wholesale power transactions. Utilities sometimes do better with limits.

Question: Assume you want to allow unregulated merchant transmission investment. Could an ITC invest outside its service territory? Could it make investments with its own money within its service territory? Do we treat inside-outside investments differently, or do we just say no?

Response: If it is outside, I argue it should be separated, but not prohibited. The entity can use its own capital, as long as the regulated entity is ring-fenced. When it is inside, regulators could say, “You are taking expertise and contracts that the company normally would do on a regulated basis and trying to do them on an unregulated basis.” Another reaction is to let the ratepayers share the risk and profit from the entrepreneurial business, if it is a reasonable risk to take. But the business must be very similar to the normal regulated activity of the utility.

Response: The merchant function should be done outside of the regulated area and it should be ring-fenced.

Comment: I am in favor of unregulated generator operations and affiliates running them, but that is because generation has the capability to be competitive. I do not see that with transmission, which is a monopoly. When someone says that transmission should be financed by merchants who will collect other than a regulated return, I have no sense that we will have competitive transmission. The reason is that people see opportunities for higher ROR for doing things that the regulated entities should do with their own transmission systems. One RTO has a chronically overloaded flowgate that causes a lot of curtailment of firm transmission. It is not being fixed because the entity in which the RTO that owns it and could fix it would receive only a small percentage of the revenues resulting from the additional throughput. The congestion costs a minimum of \$8 million annually. The fix is about \$6 million. No state siting is needed, simply the reconductoring of existing lines. I do not think the solution here is merchant transmission. The solution is to get the incentives right.

Response: If the operator of an independent transco wants to be a merchant owner elsewhere, the prohibition is no, because you always want to have

opportunities that add value. What is the public interest test? We should do this not because someone wants to. Regulation is not about accommodating wish lists, but about furthering economic efficiency in this particular sector. Therefore, you want the typical ring fencing for the utility at home; the disagreements about what that is must be solved. You do not want the affiliate to implement innovations in a distant market that it refuses to do at home. You hold the non-entrepreneurial part of the corporate family to the same high standard that it would meet in the competitive market. Make sure that the market for merchant transmission services in the destination market is a real competitive market. From the public interest perspective, you want to stimulate more diversity. And when the merchant goes to the new market, it should have no advantage as a result of its affiliation with the monopoly business at home, because otherwise you undercut the competitive market for merchant transmission services – the very attraction for doing this. In the second case, you do not want a non-utility business to provide a service that the core utility is statutorily obligated to provide or that it has accepted an obligation to provide. If we are not creating the innovation we need, we are not making the entity hungry enough for its monopoly status, or we have done something wrong in terms of compensation. We can outsource and have competition for it if we regulate away the problem of inside information and we ask if the entities really have the personnel.

Comment: If a utility is not doing these non-siting kinds of improvements and is limited to 10% ROE, why would you outsource these to a merchant who will make 20% on equity?

Question: Assuming that competition ultimately is good for consumers, if you ring fence the utilities from their affiliates and let investors assume most or all of the risks, how do the consumers benefit?

Response: If ring fenced, the competitive side of the company, as entrepreneur, takes the risk and receives the benefit or takes the loss. The regulated customers are still being regulated. I prefer this model rather than having customers assume part of the risk of a company's competitive activities. Over the last 25 years utilities would have been better off being widow and orphan utilities where with a few exceptions, everything was ring fenced.

Response: Where goes the risk, there goes the reward. You cannot say, "Investor, take the risk, but if you hit pay dirt, we take the gain."

Response: Even in the examples that purport to be successful, like PacifiCorp and PGE, there is no feasible way to line up risk and reward. There is always seepage and its extent depends on the extent of the error. Remember that in the non-competition context, the ratepayers are captive and not like shareholders who get to choose their investment portfolios. There is absolutely no rationale for making them risk takers.

Response: You can prevent seepage by defining the amount of the investment a company makes so that the regulated entity is not affected if the investment becomes a total write off.

Question: It is not surprising that unsubsidized companies are not entering, if the affiliate businesses are being subsidized into the unaffiliated area. Why not spin the affiliates off to the shareholders?

Response: Utilities and both the regulated and unregulated businesses are struggling to make the various codes of conduct work, yet not get into a situation in which they are harmed. There is a point at which you can push the standards and codes to such an extent that the only viable option is complete divestment. But as a country, we have not yet made that choice, nor is it

necessarily the best way to go. It is cheaper to have a service company that adheres to the codes of conduct and that performs functions for both sides as long as the service is provided by both. Otherwise you have entirely separate operations in both the regulated and unregulated business. Putting some operations into a service company might also benefit ratepayers because the costs go down.

Comment: In recent memory, not one state commission has said that its purpose is to extract from utility management the maximum amount of innovation, creativity and efficiency possible for that particular company. Regulation could make a practice of insisting that even monopoly companies implement best practices in every facet of their business. Do not talk only about ring fencing, but about establishing standards of excellence on the utility side.

Comment: I think the customers of holding companies that kept generation are better off than those of companies that spun off generation to a third party.

Comment: I think we can agree that we cannot go back to a widows and orphans situation. We are in a competitive environment with a lot of unregulated generation. We need greater flexibility.

Question: What should we focus on if we think about modernization instead of straight repeal of PUHCA?

Response: The repeal of PUHCA will result in more complex structures that will be harder to sort out from the perspective of state regulatory commissions with limited resources. For example, a utility might have subsidiaries in Maine, Florida and Texas. I think it will be easier to shift costs among those people because the regulatory oversight will be more difficult.

Response: Problems arise in five areas: the geographic limit on ownership of retail monopoly utilities is eliminated; the type of business limits are eliminated; capital structure in terms of level of debt and equity financing is limited; there are limitations to the number of corporations that can be piled on top of each other; there will be changes in the SEC's statutory advance review to ensure that a financing is consistent with the public interest. Perhaps the state regulatory community is too focused on fighting FERC's efforts to create regional transmission markets and not enough on preparing for PUHCA's repeal. With the exception of Westar, Aquila and a few others, utilities are masters at managing the politics of this situation. I do not think we will have hundreds of Enron's when PUHCA is repealed. But the legacy we leave for the next generation of consumers is the same set of industry decisions, more nuclear power, more coal, more consumption with everything being priced on a kWh basis rather than on marginal cost.

Question: Should or can regulators limit the types of businesses that regulated utilities go into, to avoid, for example, financing aviation or home protection agencies? If not, can they at least set rules about whether you have to pay the lower of cost or market value when buying services from an affiliate?

Response: Shareholders have a right to invest in what they choose and utilities can engage in entrepreneurial activity. The important thing is to put the right insulation, ring fencing, firewalls, or whatever you call them, between the affiliates and the core utility business. The lesson from Oregon is that even in the worst disaster, if done right, you still end up with a functioning utility. A company is entitled to go into airplane financing, within a structure where the utility is actually a subsidiary. But I do not see

how, if it's a larger holding company with utility subsidiaries and other affiliates.

Response: I advocate that a utility – I use that word as opposed to a utility affiliate – not go into unregulated activities.

Response: It is an odd concept. The regulator says, "I don't want you going into markets where it's too competitive because you might lose your hat, and I don't want that. I want you to go into markets that are not too competitive so you can dominate them and corrupt some other market." And who on your staff can assess the risks in airplane leasing or the exchange rate if the company wants to acquire something overseas?

Question: You cannot start down the path of micromanagement of the utility. A utility in power trading needs weather projections. Should weather analysis be within its bailiwick, or should it be purchased on the open market? Should the service company do it?

Response: It ought to be at market when the utility is buying from the affiliate.

Question: Are there any immediate equitable, legal or practical barriers to what I will call emergency ring fencing, when you still have to do it before the disaster may fall, but you are not in a post hoc situation and you did not do it at the beginning stages?

Response: The answer depends on the preconditions. Where Westar and Aquila had already issued debt that had been used for non-utility businesses, mid-term ring fencing is not a possibility unless their indentures permitted it. If the financing is separate, you can say, "You have to sell off xyz amounts of assets so we are back to the minimum amount" and calibrate what that is. Of course the utilities will tell you they do not want a fire sale. The Kansas commission was very direct. It said, "When you worry about your fire

sale, you're worrying about maximizing return for the shareholders and that's not our problem right now. So sell it off and then we get you back below the ring fenced amount."

Comment: One attraction of having merchant transmission investment is that while we can define the inputs, we do not know how to define the outputs very well.

Response: Regulators would worry about a company that was responsible for providing a monopoly product and then was granted other rights to conduct business where the output was not defined.

Comment: One solution is defining the products in terms of inputs, with non-monopoly products defined in terms of outputs.