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Rapporteur's Summary*

Session I: The Summer of '98: What Worked? What Did Not? What Have We Learned? How Should We Respond?

Price spikes. Multiple outages. Broker/marketer failures and defaults. Service curtailments. Red ink for some, profits for others. Calm seas and smooth sailing elsewhere. The summer of '98 has witnessed all of these occurrences. How did the various arrangements and institutions in the power sector cope with the demands? What have we learned for the future? Did events demonstrate a need for regulatory or legislative action (and, if so, what?), or is the market sorting itself out? What changes, if any, are warranted in existing industry arrangements and institutions? What lessons should we learn in order to correct the failings that were demonstrated or to reinforce what worked correctly?

Speaker One

First, some figures for the Midwest: The average weekly market index for the whole month of June averaged $263, dropping down to about $148 in July, to $39 in August, and to about $31 during the first five days of September. The big blowout occurred during the week of June 22nd: On Wednesday the 24th the average dailies ended up coming in at about $468; on the 25th, at close to $600; on the 26th at a little over $2,000; and on Monday the 29th at about $1,900. They then fell until July 21st, when they spiked back up to about $1,500, dropping off to about $600 on July 22nd.

Factors that drove prices up included:

- a widespread heat wave combined with the strength of the economy caused our loads to grow tremendously — the June peak was well above our forecast.
- the liquidated damages product, which has become the standard for forward trades, didn't hold up the way everyone had thought it would.
- the Eastern Central (ECAR) area had about 10,000 MW, or 13 percent, of its total capacity forced off-line between June 23rd and 26th, and the mid-Atlantic Interconnected Network (MAIN) was also reporting generating deficiencies on the afternoons of June 24th and 25th.
- there were huge exports out of PJM into ECAR, so PJM had to go to a maximum-generation emergency, adding to the problems that already existed in that part of the country.

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- most security coordinators, not just ECAR, had announced emergencies, so all excess generation should have been on line, but we had transmission loading relief (TLR) during the whole weekend of June 27-28, which basically locked up certain points of the grid, preventing new transactions.

On June 24th, a couple of marketers defaulted, making it difficult to trade for the rest of the summer because, as a trader, you didn't know how your position was actually going to turn out. Once a few defaults occurred, people had to go out and cover their shortfalls, and, instead of taking the risk of being unable to pick them up on the next day's hourly market because of the TLRs, they went to the daily market. So, with everybody covering the defaults on top of the generation deficiency, prices that started out at \$500 went to \$800, and — in leaps of \$300-400 at a time — traded on Thursday as high as \$2,200. Also, on Wednesday night, a plant at First Energy was taken off-line by a tornado, losing 908 MW, and the next morning American Electric Power lost 1,300 MW. These outages affected the hourly market, where there were \$7,500, and supposedly even \$10,000, trades, simply driven by the imbalance between supply and demand.

For ourselves, we interrupted our interruptible retail contracts on both Thursday and Friday, and also asked for voluntary load reductions from our customers. The public response we got for voluntary reduction actually surprised us very much — on both the Thursday morning and Friday, we were running peaks of a little over 10,000 MW and estimate that we gained about 300 MW from voluntary reduction. Of course, you can only ask so many times, otherwise people start to think they're being taken advantage of.

We see a couple things becoming very important: First, the balance between the transmission systems and the marketplace — for example, the TLR process has to be revised with a lot more coordination among the security councils and with OASIS. Second, there were instances where the hourly reservations were coming in so fast that the transmission companies couldn't acknowledge them all and allocate business for the next hour — you got turned down just because they couldn't keep up with the number of requests coming in. That could be avoided with an independent system operator (ISO), which would also have the advantage of separating the security coordinators from the operating companies, reducing the possibilities for somebody to take advantage of the market.

Speaker Two

This summer, we faced an El Nino winter, with record rainfalls, followed by a La Nina summer, with record temperatures and heat waves. We saw the load in our service territory go up by about 6 percent, the third straight year of 5-6 percent load growth. Because of this rapid growth, our surplus-generation bubble is bursting, creating the need for new generating capacity. But no one wants to have the state enter into long-term contracts where generation is financed by utility must-take contracts, and so deregulation is supposed to produce a liquid market into which investors will have confidence putting their money, while providing retail choice to customers, giving them the flexibility to decide which generation source to use, and what type of service they get.

California simultaneously established an ISO and a separate power exchange (PX), both on an unprecedented scale. There was no pilot, no trial, and no phase-in — it was done all at once to the entire state, primarily to deregulate the generation market as quickly as possible.

As we started the process, speed, not perfection, was our priority. We met with policymakers in the legislature, in the governor's office, and at the California Public Utility Commission, and made it clear that we couldn't make the January 1, 1998 start date with all the functionality that had been laid out in the restructuring plan, so there were two options: Either defer the date, or cut back on the functionality. The policy choice was to make the date, even if it had to be with less functionality, and then make improvements during a transition period up to 2001. We actually ended up starting on March 31, which is pretty close to the January 1 target, and, although the end result is something that no one is really proud of, it's something with which everybody can live.

Let me review the market structure in California. There is an independent PX running the deregulated generation market through day-ahead and hour-ahead auctions, so that if the conditions are different from what was forecast the day before, you have an opportunity to adjust your plans. There is an ISO that manages the real-time market, the ancillary-services market for regulation reserves, and some "must-run contracts," which are power plants that are necessary to achieve reliability objectives, independent of what the market does. Finally, there is independent control of generating plants' dispatch and transmission access, which helps establish confidence in the market.

Currently, the day-ahead market is functioning well, the hour-ahead market is just starting — so we don't yet know how well it's going to work — and the ancillary-services market is a mess. On the customer side, the switching went very well — if customers wanted to change their suppliers from the utility to someone else, we were able to handle it — and, most importantly, reliability has been maintained, even over this past summer.

The day-ahead market is very liquid, with 85 percent of the energy that the ISO handles going through the PX. The prices are very volatile, but I think they're also very rational, following supply and demand. Although it's inelastic right now, I'm not sure whether that's because the market itself doesn't respond well to price signals, or because utilities have frozen prices to guarantee stability to their customers, and so are absorbing all the volatility. We're also seeing prices go up and down as generators play the market, trying to decide where they can get a better price for their product, and as people experiment with their schedules on the load side. The day-ahead PX price shows the fluctuations: When the price gets higher, that's when the loads are higher, i.e. during the peak hours of the day.

Looking at the ancillary services market, a lot of people in California were scared of having a "black-box process," in which generators submit raw information—heat rates, gas prices, and so on—to a computer that automatically produces a dispatch order, making it hard to understand why one generator has been picked over another. So we decided to unbundle ancillary services as much as possible, creating four separate markets, regulated by automatic generation control (AGC), that is the ISO's computers directly control a generator's output to follow the second-to-second fluctuations and keep the frequency at 60 cycles.

The program that was developed for the ISO conducts an auction in sequence — if you have a generating plant and you want to bid your unit into all the markets, you have up to a thousand price points that you can bid in on a daily basis, and the ISO takes them sequentially. But a problem is that the computer doesn't register whether you've been accepted for spinning reserves, and so might subsequently ask you to supply replacement reserves; if it finds you're not available you might have to pay a penalty. This means that bidders have to pick either spinning- or replacement-reserve markets, as opposed to being able to say, "I have this much surplus capacity available and this is my variable price. You choose how to use it."

Such software problems can cause artificial barriers, preventing supplies from being available, both outside and inside the service territory. For example, when there were peak prices, we had about 400 MW of replacement energy supplies available that couldn't get through the ISO computers to make it to the market. Also, although the ISO is using about four times the ancillary services that were needed before the market began, we're seeing, in the words of the independent market-monitoring committee at the ISO, "inelastic and irrational procurement." The tariff has to be changed to give flexibility to the ISO, and the ISO has to be a smarter buyer.

To summarize, the day-ahead market is working well, but we need to overhaul the ancillary-services market, fix the software bugs, and be more responsive to price signals. Most importantly, we are seeing tremendous new entry into the generation market, with an additional 7,000-8,000 MW on the way, and about 3,000 MW actually in the permitting process with the California Energy Commission. Is California headed in the right direction? We certainly aren't finished, but we're getting there, and I think we'll arrive before the transition period ends.

Speaker Three

The South Eastern (SERC) region also saw problems over the summer. Although not quite as tight as in the Midwest, I think the difficulties that started there affected us because a lot of their business came from SERC, so we had to scramble to replace it. Also, we have been seeing a general tightening of supply in the

Southeast region of the country — our reserve capacity is shrinking (it used to be over 20 percent, but we seem to be on a trend line that will take it down to 10 percent), and no new interconnections have recently been built, or are planned, between control areas. Nonetheless, the load in the Southeast region continues to grow at about 2 percent (or 2,500 MW) a year. That's a lot of physical capacity that needs to be built, but isn't even in the permitting stage at the moment. In fact, we have some areas within the Southeast where load is growing at 4 percent a year, and they don't seem to be permitting any faster than those with 1 percent growth, so the tight capacity situation will no doubt continue in the future.

The Southeast region also saw the effects of above-normal summer temperatures, so that our load exceeded forecasts. Several companies decided to go into each day several hundred megawatts short of having a firm supply to meet their load — in essence depending on the market instead of any kind of physical backup. As a result, when we got into the period where tight supply caused the transmission systems to begin loading, people started scrambling to try and service their load, and the prices spiked.

I'm not quite sure why prices in the Southeast spiked as much as they did, because we didn't have the capacity outages of the Midwest. I suspect that a lot of people who had power decided that the market opportunities were just too great in the Midwest to honor contracts in the Southeast. Indeed, we found that liquidated damages were a fairly common occurrence — somebody would just call you up and say, "I'll pay the liquidated damages, because I can make more money paying you off and selling in the Midwest instead." That meant we had to jump into the market to try and replace those contracts, and we really ended up with a huge auction, rather than a market, because all of a sudden people were just trying to replace their contracts, at almost any price.

Nonetheless, the obligation to serve seems sacred — nobody was willing to talk about dropping customer load, regardless of where the price went. I run an operations center, and no one authorized me to cut back on their purchases — they never gave me a threshold where they said, "I'm not going to buy any more at this price." Indeed, as long as there is a sacred obligation to serve, I think we can expect these kinds of spikes to occur in the market.

Another problem is that, as yet, we really have no effective method for electricity storage. If you have an inventory-type problem, where you say, "When the prices are low, I'm going to buy some stuff, put it in a warehouse, and hold onto it until it's short, when I'll just pull it out and use it," then you can keep the average price where you want it. We can't do that — once we commit our reserves to serving the load, that's it: there's no warehouse with additional supply. As a result, I think we have a bit of a disconnect between the "paper world," where you can sign contracts and commit for transactions that will cover your load, and the "physical-asset world," where you actually have a piece of equipment that can generate electricity to serve the physical needs of those using it. I hope that the prices send the right signals to solve the problem, but I suspect that we're going to have a period of feast and famine until things settle down.

For ourselves, we've decided that we need to look past the person we're contracting with to ensure there's some physical capacity available to match our demand, so that we're not depending on someone who will say, "I'll pay you the damages," and walk away. It concerned us greatly that that happened, so from now on, the physical supply is going to be a very important part of our contracts.

I would agree with some of the other speakers that TLR as it currently operates is inadequate — there was a great hope that it would avoid some of the problems we thought might occur when we deregulated one side of the market, but it hasn't. We need to move to a system where the actual flows caused by different transactions are monitored, and can be curtailed if the transmission system gets into trouble. It's easy to say; I think it's going to be very difficult to do.

In closing, I should stress that we don't want to go back to a regulated world without markets. We think the markets work, and we're a big participant in them. In fact, we've structured our company so that we have actually served about 90 percent of our load through marketing contracts with two large suppliers (one of whom decided after a week that it really wasn't a business he wanted to be in, but I guess that's how it goes). We're not sure whether we as yet understand how to operate in this market, in terms of hedging and covering the 10 percent that we're responsible for, and I think we have a lot of learning to do as the market matures. It's a matter of surviving the growing pains until we get to a situation that everyone understands.

Speaker Four

One thing we did this summer was a lot of learning. For example: I don't know if anybody is willing to defend TLR anymore; the notion of a price shock has changed from prices in the \$100-250 range to four or five-digit prices; and pancaking was a complete non-issue — who cares whether you would have paid \$5 or \$10 for transmission in the Midwest when the market was at \$1,000 or \$5,000?

The high prices were in June, but they continued going into July, and really didn't settle back down until August — this was not an isolated event, although obviously June was when the big hit came. The interesting thing is that PJM, the neighboring market to ECAR, seems to have weathered the storm, even though, for one reason or another, marketers hate trading in it. Also, right after the price spikes everybody announced that they were going to build a turbine somewhere in ECAR — in retrospect, if you had had a turbine and could have got the trade-press prices, you would have recovered 30-60 percent of all your generator's fixed costs in a two-month period over summer.

PX prices were likely to change by 50 percent over an hour, despite very little change in quantity, while ancillary-service prices changed by up to 25,000 percent in an hour. When I see price run-ups like those, I immediately think of market power, although there is a difference between "scarcity rents" and "market-power rents." Scarcity rents you collect just because the market is going up, without actively behaving to withhold capacity, or trying to drive up the price. On the other hand, market-power rents occur when you actually try to manipulate the market, e.g. attempting to bid prices up above marginal cost by withholding power supplies. As far as I can see, a lot of the rents that occurred in some of the markets over summer were scarcity rents, not market-power rents, but that's just an initial guess.

In any case, who is entitled to market power? As a society, we give it to two groups: those who can get patents, and those who can get copyrights. In the summer of '98, we created a new group — people who think that they are entitled to continued poor market design if it benefits them. Because it's hard to summon up the political will to take away such "entitlements" once they're in place, I think people should be told up front that the market is evolving, and that the rules may be changed if they're not working properly.

Finally, two comments about ancillary services. First, they're not really different services — they're just variants of energy that balance the market instantaneously — so the idea of boxing them up in separate cartons doesn't make a lot of sense. Second, distributed generation could change everything, although there are incumbent groups who will probably spend a lot of time making sure that it doesn't succeed. Not too many years ago, the theory was that you could use the grid to do anything, but if you believe in distributed power, the new wisdom is that you may either not need a grid at all, or only need it to maintain power quality.

Discussion

Question: Have you got programs in place for getting capacity from your customers? If they can be paid to shed load, it's like having a virtual plant.

Response: In California we have a total of about 2,025 MW statewide from the different utilities, but it's all for reliability — it can be used if reserves drop below a certain level, and the ISO has actually called on it two or three times. I'm surprised there hasn't been more effort by energy-service providers to take advantage of the demand side, but I think people are starting to wake up to it. For example, every municipality has pumping plants for their above-ground water storage, and it's doubtful that during a system peak every single one of them needs to be pumping for those two or three hours during which you need relief. The municipalities should therefore be able to get some money for cutting back. After all, you don't need to save that many megawatts — in a 20,000 MW system, dumping a few hundred could bring prices down very quickly.

Question: What kind of a regulatory regime would be appropriate during this transitional period when the utility is torn between the historical notion of obligation-to-serve and a market-based notion of having some threshold price, above which they simply don't buy?

Response: I think there's a disconnect between (a) our desire for retail customers to see the price impacts of their usage and respond accordingly; and (b) how customers want the product delivered. That is, I'm not sure that residential retail customers want to see the volatility of the prices so that they can react to them, because I'm not sure they really understand what they can do — it's not easy for them to make investment decisions that would impact their electricity bill. Over time they will, but if they see high prices right now, they're not going to run out and change their air conditioning units or shift their family hour from 6 p.m. to 9 p.m. to be off-peak. I think what's probably going to happen is that retail customers are going to say, "I'd rather be in a consumer group where I'm together with some other folks who have similar usage patterns, and I'm willing to pay for someone else to handle the market volatility for me." So I think there'll be a company doing the buying, the market hedging, and the risk taking for them, and then just charging a flat price.

Question: Should we look at what happened in the Midwest as financial-market failure or just as market flexibility? It seems to me that there was a physical failure underlying the market failure, in that the physical market apparently had a large amount of capacity which was unavailable. The other thing is that there were localized impacts, even in extremely interconnected areas, so I'm wondering how well we really understand those connections.

First Response: I think from an overall operational standpoint, we understand the interconnections very well — it's just that, due to the TLRs, they didn't integrate. For example, you've got security coordinators sitting in Columbus and in Chicago who are completely independent, but are supposed to be coordinating their ATCs. Or, to give you another example, on July 21 the grid basically locked up — we couldn't start up a new schedule anywhere, even though there was about 800 MW sitting out at Western Resources in Northern States Power. The ECAR security coordinator said we could transfer 500 MW from MAIN to ECAR, but the MAIN security coordinator wouldn't allow anything to begin. So it isn't that we don't understand the interconnections; I think it comes down to the interaction of the security coordinators. Hence the previous comment about having a single ISO — you'd have just one coordinating group, instead of all these people doing it independently.

Second Response: You have to decide what criteria you are trying to meet when designing a transmission system. Typically you pick some level of load in an area, and then test the system with contingencies to determine whether you have enough transmission capacity in place to cope with emergencies that you think might occur. As I understand it, what happened in the Midwest was well beyond anything that any transmission planner had ever studied, because you just don't assume that there's going to be a contingency of that magnitude in your system. Economically, however, I don't know that even the prices we saw for a short time this summer provide enough incentive to go out and build additional high-voltage transmission lines — they probably wouldn't cover the initial investment.

Question: It seems to be a consistent thread that it's not that the markets haven't worked, it's that markets haven't been given a full opportunity to work. For example, I don't think that we would have got close to $10,000 per megawatt-hour if customers had been given an opportunity to bid back their entitlement to take power, which depends on evolving a contractual framework where at least some customers have specified rights to take power off the grid. I think this gets us to the issue of the obligation to serve: Are we going to get away from this almost mystical concept of an obligation to serve energy and get closer to what we have on the gas side, namely an obligation to provide a reliable connection into the marketplace?

First Response: For us, as an ISO in California, we are now an energy-delivery company, not a resource procurer. Our duty to serve is the duty to connect and the duty to take whatever resources are available at whatever price, pass them through, and allow the customers in the marketplace to respond to the price signals.

Second Response: To me, we're moving from a compact market to a contract market. We have this very vague compact that says obligation-to-serve almost at any price, which has to evolve into more of a contractual relationship, even for residential customers who, for the most part, aren't going to want to be in that business. If you look at the evolution of stock trading, with e-trading, where you can sit at your desk at home and trade stock very cheaply, there is certainly no reason why we can't do pretty much the same thing in the electricity market.

Question: I wonder if electricity prices really are too volatile. After all, you would expect electricity prices to be much more volatile than the prices for other services because we can't store electricity, so you have to maintain an essentially instantaneous balance between generation and load.

First Response: I think that most people now agree that in California a lot of the volatility is due to the market's design. If that's the case, then the volatility is uncalled for, because, for example, the problem of going from $1 to $250 over an hour in an ancillary-service market can be solved very quickly just by changing the design of the market. You should make the market as simple as possible but no simpler — I'm not against volatility, but there's no reason to create volatility for volatility's sake. In California at least, it's not unusual to see the price of energy jump by 50 percent in an hour, despite very small changes in quantities. That at least gives me pause — I'm not sure whether I want to condemn the current volatility or praise it, but I think it needs to be studied.

Second Response: While there is price volatility on the PX market, it's not really surprising — it spiked only during a few peak hours on the highest-load day, which is what you would expect. So I don't think that the California bulk-energy volatility is unreasonable or unexpected. I think it's sending very good price signals.

Comment: I'm curious about the proposition that state regulators are somehow hostile to hedging arrangements, because I remember hearing the same thing about gas hedges, but never being able to find a state commission decision that actually rejected or disallowed hedging. What I discovered wasn't that state commissioners were saying not to hedge, but that the companies were coming to the state commissions and asking them to pre-approve their hedging undertakings. Then the regulators tended to say — as they usually do in the face of requests for pre-approval — "We're not in that business, except when the statutes tell us to pre-approve a power plant, or something of that sort," and the utility executives would reply, "Oh, this is risky and new, and if we can't get pre-approval, we're not going to do it." I suspect that that's really the more likely pattern here, and that it's unlikely that a lot of state commissions are telling companies to forget about hedging. My guess is that most of them don't know all that much about it and regard it as something within management's function to decide whether or not to do.

Response: I know state regulators who have told companies that there are a lot of risks associated with *not* hedging, for which they can also get burnt, so I think the pressure is much more symmetrical than you characterize it. Furthermore, in California, the commission has specifically held that utilities don't have the right to hedge without commission approval. It's not pre-approval of specific hedges, but you have to come to the commission to ask for the right to hedge at all, and they've been very restrictive as to what they will allow utilities to do, for instance, allowing hedges on gas, but not electricity, only for a certain amount of time and within a certain dollar range.

Session II: Markets for Ancillary Services, or Ancillary Services for Markets?

Ancillary services are essential for operation of electricity systems. The label covers many things, from voltage support to black start capability. The service definitions, unbundling possibilities, trading arrangements, and pricing rules for ancillary services can have major effects on the more familiar markets for real power. Explicit identification and separate treatment of ancillary services raise familiar questions that arise in the parallel debates over transmission congestion. Where is the point of diminishing returns in unbundling ancillary services? How do we deal with the problems of market power? How do we address significant interactions in the supply of ancillary services? What are the appropriate pricing mechanisms and market structures? The early days of market operations in restructured electricity systems include a number of alternative approaches to ancillary service markets. Both the theory and practice of markets for ancillary services, or ancillary services for markets, should be examined.

Speaker One

Why should we create competitive markets for some ancillary services? I think the primary reason is that most of them are provided by the same generating units that supply competitive energy and, as we've seen in California, it's very difficult to mix a competitive price for energy with a regulated price for ancillary services. Secondly, the cost of ancillary services is not trivial — it's about 10 percent of generation. Finally, the ancillary services provided by the generators often differ from the requirements of the customers. Competitive markets encourage diverse participants to respond appropriately to price signals in order to balance costs, prices, and needs.

If we decompose the load for a particular customer into three components — the base, the ramp (which is load following), and short-term fluctuations — what are the services that together are going to meet this demand? Well, there's only the energy that supplies the base amount, and the regulation service that meets the fluctuations. Load following is a missing service, both in California and under Order 888. But, I think it's a mistake to let regulation pick up the load-following burden, because they're very different — the regulation pattern is uncorrelated, being basically short-term, random fluctuations; load following, on the other hand, is largely correlated among customers — in almost every situation there's a morning ramp-up and then an afternoon ramp-down, and almost all customer loads behave in pretty much the same way.

To provide regulation, you have to have AGC, so that you can respond to the pulses from the system operator. For load following, because it's a much longer-term service, you don't need that kind of automatic control — it can be done manually via fax or telephone. Furthermore, the amount of swing is relatively small for regulation but quite large for load following. The ramp rate — that is, how fast are you asking the generation to change — is much faster for regulation than for load following. And sign changes are frequent for regulation, but not for load following.

One question about load following is whether it's a daily or an hourly service. If it's an hourly service, you have to ask about the scheduling convention. You can't have a sudden step change in the schedule, because generators can't move that fast, so typically you have a convention that says something like, "Ten minutes before the start of the hour, we'll begin ramping from one schedule to the next, and we'll complete the schedule change by ten minutes after the hour," so you have a 20-minute ramp period. How you define the schedule affects what you call load following — the longer the schedule change, the smaller the load-following requirement. In fact, if we went to something that said, "We're going to have a linear ramp from the beginning to the end of the hour," you'd pretty much eliminate the load-following requirement altogether. But that's not how we do schedules these days, so load following is in fact a service that is needed, and shouldn't be ignored.

I want to turn to some specifics of California, where regulation — that is the service following moment-to-moment fluctuations in demand as well as unintended fluctuations in generation — is about 5 percent of the total system load, compared to 1-1.5 percent in most other control areas. Much of the reason why the California ISO purchases so much regulation is that they don't have a load-following service. Also, the California ISO received insufficient bids for regulation during the first few months of its operation, and so had to call upon the reliability must-run (RMR) units to meet their regulation deficits, which was a lot more expensive than would have been the case if there had instead been a real market for regulation. Also, those units that provided regulation were often providing energy as well, because they were doing the ramping, not just the random fluctuations, so at certain times they faced a high imbalance.

The ISO received insufficient bids at least in part because the prices were capped by Federal Energy Regulatory Committee (FERC) regulations, and units figured out that they could make more money in other markets — hence my point about not having regulated and competitive markets for services coming out of the same piece of equipment. Also, regulation is not an energy service, so on average there shouldn't be any energy produced by a regulating unit — if the system worked properly, this would not be a problem. In reality, what the ISO did was to impose an administrative addition of up to $20 per megawatt of regulation price to encourage bids, which doesn't really move you to a competitive market, but merely adds another layer of regulation.

I think the long-term solution is to first create an explicit load-following service so that regulation tracks only the random, short-term fluctuations rather than the monotonic increases in the morning and decreases in the afternoon. We also need to move to full market pricing for regulation and load following because of the coupling between energy and ancillary services markets. Any generator who's providing an ancillary service, as well as energy in response to a request from the system operator, should get paid the higher of either the current imbalance energy price or its declared energy bid, so that she isn't subjected to monetary losses for following instructions from the system operator.

Another issue is that when you've got a unit operating close to full output, in order to provide an ancillary service it has to back off and produce less energy, which means some other unit may have to come on to provide energy. But sometimes energy and ancillary services are complements — a unit can't provide regulation unless it's on and operating somewhat above its minimum point. So there are some complications about just how ancillary services markets and energy markets interact.

Related questions about reliability versus competitive markets are: What information is shared, and with whom? Should the ISO minimize the price or the cost of the service? Should the markets clear sequentially (as they do in California) or simultaneously? For example, in California it's a little awkward to move capacity from energy to ancillary services, because the PX market closes before the ISO ancillary-services markets open.

Finally, energy and ancillary services are very highly coupled and their prices should be highly correlated. Overall, ancillary services cost about 10 percent of the raw energy commodity, and my sense is that ancillary services profitability for individual generators varies considerably with system load, stock prices, and the type of generating unit. For example, hydro can ramp up and down very rapidly, so it's ideally suited to provide the regulation service, whereas a 1,100 MW coal unit is too cumbersome to provide regulation, but it's got so much capacity that it could provide the load-following service.

In short, I think we need to focus more on ancillary service markets, otherwise both reliability and commerce may suffer.

Speaker Two

The California ISO's vision statement is "Reliability through markets," which I think distinguishes us from the other ISOs in the country. So far, we're the only one attempting to meet all reliability requirements through individual markets. We have four ancillary services markets — regulation (originally set up to be a 10-minute service, but now a 30-minute service), which is the amount of regulating capacity that you can provide in a 30-minute increment; spinning and non-spinning reserves, which are operating reserves and ten-minute services; and replacement reserves--which are no longer an ancillary service according to FERC, although we still classify them as one — that can be provided to us within an hour. We have bilateral contracts for two more ancillary services, namely voltage support and black-start capability, which may be moved to competitive procurement over time.

Regulation was designed to be a zero-energy service on AGC control, but it turns out that we are using it for load following. Of the others, three are capacity-based ancillary services where the bids go to the energy market, are put in a supplemental energy stack, and essentially get market-clearing prices. Supplemental energy is in that stack as well, and supplemental-energy bids, which are accepted up to 45 minutes before the hour, can be either increments or decrements.

I think a problem in California was that the people who were capable of discussing reliability issues were the utilities, and they were reluctant to do so because everyone raising reliability concerns was trying to stop the markets. But what we're finding now is that there really were a lot of reliability problems that weren't carefully considered. We're coming up with good, creative solutions, but it's interesting that we had this perfectly designed economic system — which all the economists, policy makers, and computer people thought would work — and the operators were just sitting on the sidelines pointing out the problems. When we got into actual testing, we realized that we *did* have some significant difficulties, which were, in part, what caused a spate of amendments. Over time, though, I hope that the ISO is creating a sense of credibility, so that when operational issues arise there's a willingness on the part of all market participants to find a mechanism to address them fairly, rather than in an anti-competitive manner.

What would we do differently? One thing is that the system for balancing energy was designed to settle on five-minute periods. Although we linked them back to ten minutes, right now we can't settle except on hourly ex-post pricing, so people aren't getting the proper signals, because in certain ten-minute periods, the marginal cost is grossly different from what it is on average. That's why bidders were being hammered when they sold into the regulation market — they would be asked to move at a very high variable cost, and yet the hourly ex-post price would be below their actual running cost.

We do have a provision in the tariff that allows the operators to purchase ancillary services on an emergency basis in real time to meet reliability criteria, and that is the basis on which we've been making out-of-market purchases when we've run out of bids in the markets, in particular to balance the energy market. Because we have balanced schedules, calling on RMR means that we create over-generation problems, so one of the things we're looking at as part of the market redesign is whether we should go to negative pricing as a way to relieve over-generation. Right now, we effectively have negative pricing in that, during an emergency, we have the ability to sell off-system at a negative price, but there is no opportunity to bid a negative price within California. We do have Amendment 8, the reliability energy payment adjustment, which is an energy payment, not a capacity payment, and so doesn't violate the cost-based caps. We're also working on RMR software fixes. Hopefully, by January 1999, day-ahead RMR schedules will be included, which should also ease over-generation.

The PX is really considered to be a financial market, and people have always talked about the fact that, if you make a bid in the PX, there's an economic penalty if, in fact, your schedule varies from your bid. But no one has spent a lot of time talking about what it means to bid into the ISO. I would argue that the ISO's markets were not set up to assume that people will just default if the economics isn't right, and that, in order to maintain reliability, we really do rely on people physically delivering what they bid. But what we have seen is that people who won in ancillary services markets and were supposed to be available for spin and non-spin, were just spinning, and when the market price for supplemental energy went up to $250 they all started generating. So we had to call them all up and say, "Get back to your schedule, because we don't have operating reserves if you're generating." There were a number of conversations in which generators replied, "I'm not responsible for staying on my schedule; I've been losing in the ancillary services market, and I'm going to make up some of that money now."

So we are finding that the economic signals are not necessarily working exactly the way we had planned. We don't have penalties in place right at the moment, but are looking at the whole question of whether we should impose sanctions on people who don't follow their schedules.

The other thing that happened, apart from generators refusing to follow their schedules, was that we experienced under-scheduling of load, which got to be pretty significant after the price spikes for ancillary services. For example, on July 16 we had 7,000 MW under-scheduled on a 40,000 MW peak day. That was because we had a software problem, and ancillary services are charged based on scheduled, not actual, load, so people figured out that they could escape ancillary service charges by under-scheduling. So we have also been looking at how to deal with the fact that people are intentionally under-scheduling.

I'll finish with ancillary services price caps. Obviously, a big concern is to protect consumers from excessive prices where there aren't yet competitive markets. For example, in California, if ancillary services go up to $10,000 a megawatt, there's no opportunity for customers to opt out. So, I think it is important for policymakers to recognize that, on the demand side, there often isn't a choice about whether or not to buy.

Also, we wanted to eliminate cost-based caps to encourage everybody to bid, but we're quite concerned about what the proper cap should be to avoid the problem of scarcity rents, although we also don't want to discourage new investments. The current price caps expire at the end of September, but I anticipate that there will be strong support for extending them in some form.

Speaker Three

At some point there's a tension between reliability and markets. It shows up most distinctly in RMR contracts, which have a market component and a regulated component, all condensed into one contract for a particular set of units. Is the presence of these contracts having an adverse effect on ancillary services markets?

For a unit to be considered RMR, it must be necessary to operate it during certain hours to maintain reliability, and there needs to be insufficient competition to check the locational market power that the owner might exercise because the unit is needed for reliability. (In some cases, although a unit may be needed at times for reliability, there are enough competing units serving the same function to make an RMR contract unnecessary.)

The objectives of an RMR contract are:

- to establish a price for reliability services when the seller has locational market power
- for the ISO, to ensure that units are available when needed, setting performance obligations and certain technical and financial standards which the RMR owner has to meet, as well as providing sufficient revenues to keep the RMR owner solvent
- to encourage and facilitate market participation by the RMR unit without undermining the first two objectives (which is where a tension exists between the reliability function and the market function).

Payment for energy for ancillary services is fairly well-defined in must-run contracts. There's a reliability payment, equal to the total fixed costs for the year divided by an expected megawatt-hour production, and a variable payment, which is the variable cost including fuel and, if necessary, a start-up payment. On the other hand, payment for ancillary services capacity can be ambiguous, differing from contract to contract and, in some cases, subject to dispute.

In its report, the Market Surveillance Committee makes a number of contentions about what the RMR-contract structure does to the incentives for RMR owners to withhold capacity in the ancillary services market. For example, they say that RMR contracts are contributing to the inefficient operation of the ancillary services market by creating perverse incentives for generator bidding, because expensive RMR units have little incentive to bid into the market when there's a reasonable chance that they'll be called upon under RMRs. But is that true?

To decide, you have to look at the two reasons why the ISO would call upon an RMR unit for ancillary services: One is if there are insufficient bids in a particular ancillary service market; the other is if there are locational bid reliability concerns.

In the first case, the outcome for the RMR owner is better if he bids than if he withholds his bid because, subject to the ISO cap, by bidding he's assured that some of his capacity will clear due to the bid insufficiency. On top of that, the RMR owner, as with any bidder in an insufficient market, can set the market-clearing price, which may be a problem, but is unrelated to the RMR contract. If he withholds his bid, on the other hand, he may or may not get called, because the ISO can use any of its RMR units, not just his. Furthermore, even if he is selected, he'll just get the payment in the RMR contract instead of the market-clearing price that he could get by bidding, which is only beneficial in the rare situations when the RMR payment exceeds the ISO cap.

In the second case — where there's a local reliability concern, and the RMR owner knows it and has sufficient reason to believe that he's going to be called as an RMR unit — if you assume that the owner's opportunity cost is the RMR payment, then, like any other rational bidder, he's going to bid at, or above, his opportunity cost, which still doesn't suggest that he should withhold his capacity, again unless the RMR payment exceeds the ISO cap. If his bid is excessive, it won't clear the market — with the exception of insufficient bids, discussed above — but he may still get called as RMR, so there's still no reason to withhold capacity.

To summarize, notwithstanding the contention of the ISO Market Surveillance Committee, the presence of RMR contracts doesn't motivate RMR owners to withhold capacity. Withholding is only likely to occur if the RMR payment exceeds the ISO's bid cap, which almost never happens, and, even then, it's uncertain whether the owner is going to be called as an RMR unit. In cases where there is bid insufficiency, the RMR owner is really in no better position than anybody else.

Speaker Four

PJM took the opposite road to California with ancillary services, in that we started looking at unbundling the power pool back in the early '90s, when a disagreement on how congestion pricing should work moved the spotlight away from ancillary services. I don't want to say ancillary services were an afterthought at PJM, but, in reality, the priority was to get the energy market on line. I think we've successfully done that with the implementation, since April, of locational marginal pricing (LMP), and so now we're in the process of going back and looking at our ancillary services to see whether we are going to make them closer to markets.

Prior to Order 888, PJM was a tight power pool. Essentially, we were dispatched; we were a single control area; we operated under a reserve-sharing agreement; and we were highly integrated, with the system operators controlling the scheduling and dispatch of generation for both energy and reserves as a single entity.

As a tight power pool, ancillary services were basically shared, taking advantage of both load diversity, which makes load following easier, and economies of scale. Members were not required to maintain specific levels of reserves; rather, PJM maintained the reserves on a control-area basis, and we assured reliability through the commitment and dispatch.

As we moved toward an ISO and unbundled the generation market, our desire was to keep the benefits of integrated system operations, while still opening up our markets in compliance with Order 888.

Schedule 1 was fairly straightforward: we just took the operating cost of running the ISO during a given month, figured out how much the transmission customers used, and everybody paid a *pro rata* share. For network service, it was their load; for point-to-point service, it was based on their scheduled energy. That's a very simple method, so now we're going to try to unbundle it further, applying higher costs to those who use more of our services.

Schedule 2, the reactive support, really came out to be a $1 per kilowatt-month demand charge based on transmission zones and applied to the transmission customers. We're not doing much with that right now.

Schedule 3 is regulation, which was probably the closest thing we had to an unbundled service in our tight power pool. We carry 1.1 percent of our load for regulation on the control-area level, which is then allocated to each load-serving entity based on the amount of load they have during the hour. The load-serving entities can choose either to self-schedule non-generation, to enter into bilateral contracts to buy regulation from other parties, or to allow PJM to schedule somebody else's excess regulation if they are deficient. And again, PJM will make sure we have enough regulation to cover the control area's obligation.

Any regulation that's scheduled by the ISO above the party's obligation right now is based on a cost-accounting formula. That is, any unit certified to regulate is placed in one of three classes — either base, marginal, or peaking — depending on its relative energy rate. We then calculate an opportunity cost for each of the units that are regulating in a given class by looking at the average cost for all the units in the class and the average market-clearing price that the unit would have received if it had instead been running at full load. We figure out the difference, and have a multiplier — currently, a factor of two — to provide an incentive for people to supply regulation. We can increase that multiplier to ensure that we are getting adequate regulation, although right now we get enough for PJM to operate and meet our obligations.

That being said, we are in the process of proposing a market-based regulation product. It's still the PJM obligation, it's still assigned based on load ratio share, but the difference is that now selling excess regulation into the market will be bid-based.

PJM schedules generation based on energy prices, and we usually have enough ten-minute spinning reserves and supplemental reserves through our normal economic dispatches. We rarely, if ever, have to take action to create additional reserves because we have 540 units for a 48,000 MW pool, so, in any given instance, there are all kinds of generators being loaded and unloaded to provide the reserves.

Our bids consist of a start-up, a no-load, and an incremental energy bid. We guarantee that any unit bidding into the market, participating in the central dispatch, will fully recover its costs. Really, we've lumped Schedule 5 and Schedule 6 (spinning and supplemental) back together, because we don't differentiate them and we don't assign specific obligations to any individual member. Instead, we have control of their obligations for both spinning and supplemental, so the cost of operating reserves is really the cost to make a unit whole over a given day. We take each unit that we ran and compare its bid to the value that it received in the energy market to determine over a 24-hour period whether it recovered all its money. If it didn't, and we ran the unit, we will make up whatever difference there was between its actual bid cost and what it received through the energy market.

One problem is that it's almost impossible to determine the reason why a unit didn't recover its bid. It could be a missed forecast; it could be because we put it on at minimum just to provide operating reserves, knowing it would lose money; it could be because market conditions have changed; it could be because other units have tripped; and so on. So it becomes very hard for us to determine what is in the operatingreserve charge.

Another problem is that a significant portion of the actual operating reserve charge is really "uplift," in that a lot of units don't recover their bids only because they're marginal. That is, they were the last unit running, so the energy price that they bid set the clearing price, and so they obviously never recovered their start-up or no-loads; or they were stranded, in that they were scheduled because we anticipated a certain load level with certain transactions, and one of our members either curtailed his purchases or decided to start up a couple hundred megawatts of extra sales.

Schedule 4 is what we've always called "PJM Interchange." PJM is responsible for maintaining the balance between generation and load on a control-area basis, and any part of PJM can self-schedule. They can't self-schedule to their load, but they are by no means required to maintain a balanced schedule. They do not have to match the generation load and, in fact, almost never do. Rather, they self-schedule any units they want, for whatever reasons, and then turn over the remaining units to PJM to operate under central dispatch. PJM will schedule them based on bid prices, and, after the fact, we know PJM maintained the balance between flow and generation. Then we simply go back and look at each member to see whether they were over- or under-supplied, and the pricing is done by LMP, which also takes care of congestion of the system or the energy flow. Again, PJM has always operated this way, and it works extremely well — it's what people refer to as our spot market.

Discussion

Comment: The California ISO, if I understand correctly, procures ancillary services at about 77 percent of its energy cost, and PJM is procuring them at 1 percent of their energy costs. Also, PJM has a neighbor where, for a significant period of time, the markets were clearing at 3-10 times the PJM market price. So why do people condemn PJM and its "central planning"? Their numbers this summer looked pretty good, and surely the ultimate goal of Order 888 was not to create a competitive generation market for its own sake, but to lower consumer prices through competition.

Comment: From a generator's perspective, the difference between energy and ancillary services is that with energy, we're selling a product, and with ancillary services we're selling an option. Only if the option is exercised do the two look the same — the product that you're delivering through the option is just the product that you're selling under the energy market. Otherwise, you might sell the option to one person, and the product to another person.

Response: That's true for the reserve services, but not for regulation, because that's not something that you might call upon once in a while — by definition it's the generation you use to balance your load, minute by minute, so you're constantly using it. For example, if you have a 500 MW coal unit that's running at 400 MW and you sell 50 MW of regulation, the system operator has bought the right to run your output anywhere between 350 MW and 450 MW, and she can change you as fast as your ramp rate allows. So, if you have a 10 megawatt per minute ramp rate, she can move you from 350 MW to 450 MW or back within 10 minutes. Then it's not clear what output you could sell to someone else, because she could have you up at the top, and then 10 minutes later have you down at the bottom.

Question: In the market, can you use re-dispatch to eliminate transmission constraints?

Response: In California there are at least two zones, and we sometimes accept ancillary services bids from one zone or another in anticipation of congestion. So, I think the answer is that if a system operator knows that there's likely to be a congested interface, he might accept bids for more operating reserves than would otherwise be needed. For example, I might need operating reserves equal to 6 percent of projected daily load, but I'd better make sure I've got 6 percent of the load for this pocket here, and then 6 percent for this pocket over there, not just 6 percent averaged over the whole area.

Question: Given the experience that you've had to date, does it still make sense to separate the PX from the ISO when the two markets have to work very closely together?

Response: It was a fundamental precept of what California decided to do, but I would not suggest that it's the only way to do it. I do think that you can take the need for division to extremes. There has to be a little rationality, so that people can at least be allowed to communicate and integrate with each other. In retrospect, there's a lot more we could have done, but I don't think the separation is inherently inefficient. Everything the PX does affects the ISO, and vice versa, but what firm wouldn't be driven by a customer that represents 80 percent of their business, which is the situation the ISO is in?

Question: I'm wondering what we are changing as we go from cost-of-service to market-based pricing. For instance, if we put in good markets for ancillary services, are we really going to change how units operate?

First Response: On the demand side, although customers differ in their use of ancillary services, no proposal that I've seen differentiates among them; you charge every customer on the basis of their load ratio share or their average megawatts over an hour. Perhaps the starkest example would be, say, an electric-arc steel furnace on one hand, and an aluminum mill on the other. Per megawatt of load, the steel mill probably has a regulation requirement of the order fifty times higher than the aluminum mill, so someday the aluminum mills are probably going to say, "I don't want to buy your regulation service, because I'm not using it." System operators will then need pricing that is related to what customers are actually using, which will in turn provide incentives for customers to change the way they operate. On the supply side, generators differ substantially in their ability to provide these services depending on their ramp rates and their turnaround times. For example, hydro units are ideal for providing regulation, because they've got very fast ramp rates and don't have the inefficiencies of a fossil unit when ramping up and down. In the long term, I think the market will differentiate among generators, in that particular generators will be providing particular services because they're the ones that can sell at a low price and still make money.

Second Response: From a generation perspective, the sheer number of people in the game will play a role in what is different between the past and the future. Also, the operation of the units at our facilities is significantly different than before. We have multiple units that were built in the 1940s, which very rarely ran. But if they're small units, they start up faster and are more flexible, and so they now have an option value that was never realized under cost of service. The buzz word today is "optionality." There really is option value inherent in these units that comes out in a market based system and clearly impacts the way the system operates.

Session III: Federal Electric Restructuring Legislation

How is the pace of events in electricity markets being viewed on Capitol Hill? What is the political climate on restructuring legislation? How is the Administration proposal being taken? How much authority will Congress be willing to delegate to FERC (e.g., mandate ISO membership or disaggregation, pre-empt state regulation on retail competition, provide explicit subsidies for renewables)? How is the new reliability organization viewed on the Hill? Will Congress continue to allow reliability to be regulated on a self-policing basis by the industry, or is there a perceived need for governmental intervention? What are the specific bills and their approaches that are currently at hand? What are their prospects? How are the efforts of the states to effectuate restructuring being viewed in Washington? What perspectives among legislators, if any, are emerging on restructuring?

Speaker One

There are ten electricity bills pending before the Senate Energy and Natural Resources Committee at this point. Two of those are Public Utility Regulatory Policies Act (PURPA) repeal bills, one is a Tennessee Valley Authority (TVA) bill, and the other seven are more broad. In addition, there are a number of electricity bills pending before other Senate committees that will be considered as part of comprehensive legislation, if we ever get to it. Two of those are before the Finance Committee and deal with private-use exemption, and the other is the Public Utility Holding Company Act (PUHCA) repeal bill, which was reported by the Banking Committee and has been pending in the Senate for quite some time. Senator Bumpers, who is the ranking Democrat on the Energy Committee, has strongly opposed Senate consideration of stand-alone PUHCA repeal. He believes that PUHCA has outlived its usefulness and ultimately needs to be repealed, but only in the context of comprehensive legislation.

The Energy Committee held seven hearings on electricity last year, although none were on specific legislation. Indeed, until the Committee starts building consensus, sorting out the content of the bills, and figuring out what issues they have the votes for, it's going to be pretty difficult to predict what the final product might look like. There is one more electricity hearing scheduled for September 24, 1998, at which the Committee hopes to have FERC present the findings of its investigation into the "summer price spikes." Although the majority staff has indicated that they would question the purpose of going forward with the hearing if FERC doesn't yet have its report, Senator Bumpers is anxious to have the hearing to look not just at what happened and why it happened, but also at how some of the provisions in the pending legislation would perhaps mitigate price spikes in the future.

Finally, note that there's an inherent conflict between trying to have the federal government move forward with restructuring legislation now, before all the questions have been answered, versus waiting for the states to go first, and then all of these states having grandfathered their programs and not wanting the federal government to overturn them. At a bare minimum, I believe that the federal government has important things to do in the area of transmission, for example by clarifying some of the uncertainties in current law.

Speaker Two

In the House, we didn't get to a vote on electricity restructuring legislation. We were going to have a mark-up in the spring, and so there were members trying to come to grips with the issues, but I think they discovered that they just weren't ready. There had been an assumption in the Commerce committee that this would be like telecom, but, of course, it's harder than that. Not only is telecom different, but at this point people aren't necessarily drawing parallels because they're not sure if they like the way that the telecom restructuring has turned out.

We don't have continuity of leadership. Congressman Schaefer, who is a very well respected chairman, is leaving and we aren't certain about who'll replace him. Also, because all the House chairmen took six year term-limit pledges, assuming there's no change in control of the House, Congressman Bliley, who's the full Commerce Committee chairman, will be facing his last two years in that role, and there's already a lively battle going on among his potential Republican heirs.

With respect to next year, I think we'll hear from the House Judiciary Committee, which has authority over anti-trust, merger, and market-power issues. They've had a couple of hearings, they've got an awfully good staff, and they're very bipartisan, so we may find ourselves sharing this issue with them whenever we get back to legislation. In general, I think we'll see the House debate shedding some ideology for the sake of greater pragmatism — there'll be less interest in telling the states what to do and when, and greater emphasis on looking at specific issues, such as: Should we be worrying about market power? Should we be worrying about reliability?

It is possible that we'll see people pushing for PURPA repeal, which amazes me because I can't understand what threat PURPA presents to anybody. More substantially, I think we'll see a real run at PUHCA repeal, although I would be surprised if PUHCA is put on the Committee Resolution as long as Senator Bumpers is there.

In the last draft bill we looked at in the House — which was drafted by another outgoing member, Mr. Paxon, and was largely thought to be Chairman Bliley's attempt to pull things together — we ran into some very interesting intellectual issues, mostly to do with the kind of problems with which California has struggled. For instance, if everyone gets to choose on day one, what happens to existing contracts? It seems like a simple question, but this great ideological push to say everybody will have a choice really amounts to letting one side break existing contracts. The bills being presented were internally inconsistent. On one hand, they said that everybody should have choice, and on the other hand, that all contracts, rate schedules, tariffs, settlements, and so on should be preserved. If it were determined by a court that Congress really meant that everybody had a choice, so that you could in fact break contracts, then you have questions about whether or not Congress effectively broke the contracts, in which case you get into nasty issues about whether people can sue the federal government for their losses.

A second question we stumbled over was: On day one, when this system goes into place, who regulates what, and under what authority? What residual duties and responsibilities do states have? Are they assigned those duties by the federal government? One of the legislative proposals had four new federal standards, meaning that this bill would lead to 200 new standards of proof throughout the country, which hardly solves the "patchwork-quilt" problem. More practically, I think a lot of the bills finessed the question of what state regulators are supposed to do on the first day or the first year. If there isn't a state law in place telling them how to act, should they make one up? And what if they can't get it through the legislature?

Also, note that if we stray into the realm of providing federal standards, then there might be Tenth Amendment difficulties, that is, problems of having state officials commandeered to enforce federal standards, which is getting tougher and tougher to do.

My final thought is on the environment. At the Environmental Protection Agency (EPA), Carol Browner has been very effective at crafting additional clean air acts and other regulations. They're very tough and they're holding up, putting a lot of pressure on utilities. And, although we're not going to see the Kyoto agreement ratified any time soon —frankly, depending on what happens in this Administration, the climate-change initiative may recede even further into the distance — the nuclear utilities feel they're not being given credit for their environmental benefits and that they're being faced with near extinction due to federal mandates that would require them to justify their costs and meet the market test, without stranded cost protection.

Speaker Three

The country is moving towards competition in the electricity industry. We at the Department of Energy have done some modeling and analysis which shows that, along with accompanying environmental benefits, the nation could save $20 billion a year in the electricity sector by 2010, although I personally consider that to be an extremely conservative estimate.

It is clear to many of us that it's time to move from a regulated monopoly economy to a competitive economy. Historically, you could save money by not duplicating the distribution system and having a single company serve a whole territory. The same thing was true with the economies of scale for generation — the bigger the power plant, the more efficient it was, and so the cheaper it was — and economies of scale for capitalization — the bigger the power plant, the bigger the capital requirement, so it was easier for a larger company to match capital with physical needs. Well, those were the reasons that a regulated monopoly made sense: You granted the monopoly in order to achieve efficiencies, and you regulated to ensure that the savings were passed through to the customers.

But none of those reasons are true any more. You no longer need multiple wires to have multiple sellers, because you can keep track of who's selling to whom, and the economies of scale for generation have turned around, because smaller plants are more efficient and don't need the huge capital structure of a regulated monopoly. With the physical and economic reasons for regulated monopolies gone, pressure is mounting to be released from a structure that has become restrictive and doesn't realize the efficiencies that are available in a competitive market.

So, it's time to change. Many states have realized that, and we in the Administration have realized that. We believe Americans should have the right to pick their own electricity supplier, and that customers will do better for themselves than monopolists and regulators can do on their behalf. But, since the states are going ahead and doing retail competition, the question arises: Why should there be federal legislation?

We need legislation at the federal level because of the ways in which the monopoly system had been applied. First of all, along with increased competition has come increased regionalization of trading, largely as a result of technological developments that allow power to be transmitted further than previously possible. When the system was originally developed, transmission systems pretty much just served each utility's territory, with little trade across regions, or even across utility boundaries. As the technology developed in the '50s and '60s, it became easier to transmit power greater distances and, with that ease, wholesale transactions became more and more common. Simultaneously, the law began to change, first with PURPA and then with the Energy Policy Act, to allow freedom from the old restrictions that made the regulated monopolies the only electricity traders.

So you had increasing trade in electricity at the wholesale level and, with that trade, an increased need for understanding the market on a regional basis, instead of on a single state or single utility-system basis. The legal structure on which the regulation of the monopoly systems was based recognized the relative insularity of the old system. In fact, PUHCA was in part intended to seal into place the necessary relationship between federal and state regulation, so that states could be sure that they were able to regulate what they needed to, and the federal government could regulate what it needed to, namely the inter-state transactions of very large systems.

With growing trade and increased regionalism, the distinction between federal and state jurisdictions has begun to break down, and is becoming a point of controversy. Although people sometimes think that state/federal regulatory jurisdiction is about as tedious an area as you can find, you have to remember that as dull as it might seem, almost all of the electricity cases that have gone to the Supreme Court have been over this very issue. As the regulatory structures no longer fit the way business is actually being done, you find that this set of issues, which have always been in conflict to some degree, are becoming even more complicated.

The point is that we really need to do something to clarify and straighten out the federal/state jurisdictional roles, and that's going to be a very difficult and controversial task. I think that over the last 10 years or so, states have gone through several stages on this set of questions. For a while there seemed to be a growing understanding that states were going to have to begin joining together, and there were several attempts at regional regulatory frameworks, none of which ever really worked out, although an earlier bill by Senator Bumpers allowed regional regulation for integrated resource planning, without it being pre-empted by the federal government.

The markets are becoming regional, but regulation isn't. At certain times, states have moved toward understanding and accepting that regionalism is happening, and that the choice is between federal pre-emption or some kind of regional structure. But I currently sense a move away from that growing sense of regionalism on the part of state regulators, partly because of the nation's political move to the right, with its associated notions about states' rights. So, although this issue may get more difficult rather than easier, it's one of the things that needs to be dealt with if we're to have a rational, competitive electric industry.

Another set of concerns that we see as increasingly important are reliability issues. We've had massive blackouts in the West, and some people would attribute the price spikes in the Midwest in part to reliability concerns. The self-regulating structure that NERC constituted did a great job for a long time but, in light of all of the changes that are going on, something more has to be done to ensure reliability. A number of initiatives are under way to try to deal with these issues, but I think federal action is necessary in order to handle them properly.

Another thing that has to be dealt with at the federal level is the fact that we own several utilities — TVA, Bonneville, the power marketing administrations, and so on. If there is going to be a competitive electric industry, those utilities should be a part of that: We can't leave them out just because they are federal and we don't know how to recover stranded costs for the federal government.

Lastly, there are market power issues, and I think the only place that regional market power issues can be dealt with is at the federal level. It would be unfortunate if, as some people have said of other deregulations, we do this thing, get it wrong, and see customers' prices increase.

Let me now describe what our bill does, and a few of the solutions that we've devised to resolve some of the political problems. First, we want to encourage states to implement retail competition. We require that states give their customers the right to buy power from whomever they want by January 1, 2003, although we would permit the states to opt out of that requirement if they find that their customers would be better off with some other system.

Along with the requirement that states give the customers the right to choose, we would establish the principle that stranded costs should be recovered, but leave their actual recovery to the states in the same manner that we're leaving them to define what constitutes "retail competition." We feel that stranded costs are, and should continue to be, a state issue.

We intend to protect consumers by facilitating competitive markets. First, we believe it's tremendously important that, if customers are going to be asked to make choices, they should have enough information available to choose wisely. We would therefore require some kind of labeling that would give customers information on prices, environmental effects, and other factors necessary for them to make up their minds about where they want to buy their power. The Secretary of Energy would make rules to establish this consumer disclosure requirement, as well as the mechanisms for implementing it.

We'd primarily give the authority to address market power problems to FERC, investing it with the power to require divestiture of generation or transmission resources, if necessary, although usually the utility would come to FERC and propose a plan to mitigate its market power, which FERC would be able to approve or amend.

We would repeal PUHCA, not in a vacuum, but in the context of customers being able to pick their own electricity supplier. Unless customers can protect themselves by having the right to choose other suppliers, the federal protection provided by PUHCA should not be removed. We would also close some loopholes that repeal of PUHCA would create, for instance by authorizing FERC to review mergers.

On the reliability of transmission, the system would still look a lot like it does at present, with national and regional bodies but, in addition, we would give FERC the authority to review transmission reliability rules, and require that those rules include sanctions, penalties, and enforcement provisions so that things become somewhat less voluntary.

We would encourage continued support for public benefits programs — e.g., for research and development, energy efficiency, and low-income assistance — by creating a public-benefits fund that would take, at a maximum, a mill per kilowatt hour out of the system.

We would create a renewable portfolio standard that, by the year 2010, would require 5.5 percent of every supplier's generation portfolio to be made up of renewable resources (about a two-and-a-half-fold increase over the current mix), although we would allow trading to help realize that standard. To encourage solar and renewable resources, we would use federal law to clarify that net metering is not a violation of the federal power-pricing structure, so that certain renewable resources could just run their meters backwards in order to sell back to the generator from which they're buying.

Finally, on a related point, we believe that it's time to do something about NO_x trading. If we're going to have a NO_x-control system, we ought to structure it in the manner that is most efficient. We wouldn't change EPA's authority to require NO_x controls, but we would authorize them to institute a cap-and-trade system for purposes of economic efficiency.

Discussion

Comment: One piece of conventional wisdom that needs to be re-thought is just how difficult it is for the utilities to have what they consider to be inconsistent regulations from state to state. I think utilities vastly overstate how hard it is for them to operate with different state rules and provisions. They've done very well over time with exactly that, and it's not really a huge inefficiency.

Question: First, does the Administration's proposal say that there should be both wholesale and retail stranded asset recovery? Second, how are stranded assets being defined?

First Response: The federal government endorses the principle that stranded costs should be recovered, whether they are at the wholesale or the retail level. It leaves states with the authority to determine how those stranded costs are recovered at the retail level, but gives FERC back-up powers to determine stranded cost recovery should states lack such authority, although there would be no federal appeal. An interesting question arises if a state legislature doesn't give authority to the public service commission. In that case, there is an ambiguity about whether the state legislator's conscious action in not giving authority means that the state had the authority but didn't exercise it, or whether FERC could step in as a back-up.

Second Response: There may be limitations on Congress's ability to dictate who decides retail stranded costs, for example under the Tenth Amendment. But, if I can make a political prediction, I don't think this is going to be an issue in Congress, because it's basically been decided that there will be stranded costs in the system, and that they will be negotiated at the state level unless referenda demonstrate that the public is really unhappy. Whether that's right or wrong, I think everybody accepts that it's politically necessary.

Question: What do we do about eminent domain? There's an interesting problem, namely that most state statutes were written without any concept of an independent transmission company, so you have no eminent domain if you're not, for example, a seller of power.

Response: When Senator Bingaman was writing his bill, he had a provision for giving FERC the authority to order the siting of new facilities in connection with a board of the affected states. The question of whether he should take that next step and provide eminent domain authority came up, but it was not something he wanted to take on at that point — I think he would have lost if he'd tried. So the hope is that the regional transmission groups will match marketing regions, and that states, when they get involved in these kinds of compacts, will understand the efficiencies and be able to convince their citizens that they should be able to build lines where they are necessary.

Comment: It's very important to acknowledge that what we're restructuring is not just the industry, but also consumer protection. In that vein, a few years ago, when the relaxation of regulations came up, we used to say that it would probably mean a great increase in the use of antitrust law as a tool of social policy. But in fact no one seems to be vigorously reviewing the mergers and acquisitions of utilities or telecoms — for example, the Justice Department seems very casual about them.

First Response: I agree with what you're saying about consumer protection. I think Senator Johnson woke up one morning and decided that restructuring was a neat idea, that it was going to be good for the consumers, good for the utilities, good for America, so let's go out and make everybody do it. Senator Bumpers, I think, came at it from an entirely different perspective. He saw it was already happening in the states, and thought that the only way to protect consumers was to get the federal government involved, so he has, for example, provisions in his bill that increase FERC's ability to deal with market power issues and merger approvals. One of the reasons why he has so strongly opposed repealing PUHCA prior to enactment of comprehensive legislation is that, although he is willing to accept the theory that market forces will be able to substitute for Securities and Exchange Commission regulation, if you repeal PUHCA first and enable the holding companies to lock up the market, you'll never get to proper competition.

Second Response: We in Congress have heard very little on behalf of residential consumers in connection with this legislation. For instance it's only recently that the Consumer Federation of America even came up with a position. I've always thought it was ironic that the folks who were pushing hardest for customer choice were the guys who probably have a good shot at getting high business retention rates. So I think you're right: We just don't hear anything from consumers.

Comment: Something very important happened during the last year, namely the introduction of the security coordinators and TLR. There was a change when that happened because, before that time, NERC was a standard-setting entity, but didn't have anything to do with operations. In this case, they responded to what they considered to be an imminent catastrophe, caused by the way the rules have been set up, and created the security coordinator system which, although it absolutely had to be done, is a mess. What I'm worried about in this process are the real problems of reliability, of blackouts, and of destruction of the market's effectiveness. For example, we've heard people talk about how the amount of trading that can actually be done has been going down because of the highly restrictive rules that are being imposed to manage reliability problems. It seems to me that, whether you want comprehensive legislation or not, if we delay we're going to get ourselves in real trouble, and all of the other discussions might become irrelevant. For example, I'm surprised that in New Zealand there hasn't been a bigger backlash to the blackout of the financial district, which could be attributed to problems with the market, and to the fact that they didn't have mandatory rules for dealing with reliability problems.

First Response: It's now part of the Administration's proposal, and in several other bills, that we infuse a self-regulating entity with public authority to enforce reliability. Some of us take a very expansive view of the Federal Power Act, namely that, although traditional definitions don't deal with it, reliability is now absolutely central to market operation and to the issue of non-discrimination. But people foresaw that there's an inevitable clash between the market and the command-and-control rules for reliability, which is going to be thrown at FERC to resolve. Legally, giving FERC overt, clear-cut authority would be helpful, but I don't think it is absolutely essential.

Second Response: I think the question you raise is an interesting strategic one. It's true that something has to be done about reliability, but I think we're on the right track. The security coordinator system is an evolutionary step, which means that for the first time the reliability structure is taking on a different character. But I also think it's an initial catalyst around which regional institutions may evolve, because it's something that everybody is participating in, almost perforce, and that in itself may define what the appropriate regions are for whatever compacts may evolve. Something also has to be done about market power and state/federal jurisdictional issues. They may not seem to be pressing before-the-fact problems to members of Congress, but I worry that they will become pressing after-the-fact problems if legislation is passed that allows market power to develop before competition evolves, causing prices to go up.

Comment: Going back to the reliability issue, I want to stress that we haven't had two levels of regulation in this country, we've had three — that is we've had the third level of industry self-regulation. The industry was literally about 40 large firms, but their power is being dissipated, partly because the large utilities are increasingly concerned about antitrust issues. They want to get out of supporting NERC, so we need something to put in its place. Now there's a sense in which we legitimized the system of self-regulation by drawing a bright line between "reliability" and "economics," with the regulators dealing with economics and the utilities allowed to get together, free of antitrust considerations, to deal with reliability. Nobody ever believed that separation, but as a regulator I swore by it, because that's how we legitimized the system of self-regulation. Now, that fiction is being stripped away by the TLR process, and we are being forced to realize that every reliability standard has a commercial impact, and every commercial practice has a reliability impact, and nobody is going to trust the big players to make the right tradeoffs between the two.

Response: Furthermore, right now we seem to have a set of incentives that are not leading to capacity being built in the places where it's needed to preserve reliability standards and efficiency, because the old players don't want to build and the new players don't find the rules appropriate. Meanwhile, reliability margins are shrinking. I don't think we've got time for Congress to fiddle while the system burns.

Question: In many states, if you are talking about market power and potential divestiture, whether voluntary or otherwise, you have to deal with hydro. One of the things that we found is that, as hard as it may be to sell fossil assets, it is extremely difficult, if not impossible in some watersheds, to sell hydro assets. How, if at all, is this whole issue being discussed on Capitol Hill and in the Administration?

Response: I believe Senator Thomas is introducing, or is contemplating, legislation to deal with some recent (and what he considers to be mistaken) FERC hydro decisions, so on that level there's probably going to be some discussion. But if the reason that it's impossible to divest hydro assets is that they cost so much to run, then they probably don't have appreciable market power unless it's in association with something else within the company that owns them. On the other hand, if it's just that it's incredibly complicated, with the recreation agencies, the resource agencies, the local communities, and so on, then not much is going to happen unless there's some crisis, because the minute you raise the issue, you also raise all these other questions about fisheries, about environmental protection, and everything else.