Harvard Electricity Policy Group
Special Session: Western Issues

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RAPPORTEUR'S SUMMARY*

Session One: Market Design for the West: Adaptation and Implementation

Coordinated spot markets, locational marginal pricing (LMP) and financial transmission rights under FERC's proposed Standard Market Design (SMD) require some activities and allow others. The design provides a framework for transmission open access and non-discrimination. The details of implementation are important. The elements depend in part on the nature of the physical system, and interact strongly with trading arrangements. Everything is constrained by requirements for reliability and workability. Experience with many of the critical elements of the design in other markets can support adaptation in and for the West. Recognition of the practices and conditions in the West can shape the details and the priorities for implementing critical market elements. How do the requirements of SMD intersect with the needs of the West in a wholesale electricity market with open access and non-discrimination? What is required and what is allowed? What are the priorities? What is the best way to facilitate the transition?

Speaker One

What is required and what is allowed by SMD? The law requires giving access. Giving wholesale access to a network and thus the market is necessary but not sufficient by itself for successful deregulation. Competition at the production level will control prices if you get effective competition. Of course, there is nothing in SMD that actually restructures, with one exception. Another important point is that there is no particular reason to have customer choice for small customers; the benefits of all that retail access are elusive. SMD deals with the short-term issues and will offer the minimum amount of restructuring to make access work. The transmission system has to function in a way that if the same people own a generator and the transmission system, they get no favor from that particular arrangement. Wheeling failed to come to grips with the four things that must be in place for any access scheme to work: schedule the unit;

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solve for imbalances; deal with congestion; procure ancillary services. All four increase efficiency without any deregulation at all. The clearest evidence is the old, tight power pools like PJM and New York. They did not presuppose any sort of deregulated generation or require any kind of customer choice, and they used transmission more efficiently.

Many people think we need more transmission, but we have no idea if there is enough because it was used so inefficiently in broad parts of the country. Until we go to a system in which we find out where people are able to enter a market and compete freely, we will not know. Those transmission constraints are the important ones, not the ones existing now because of some set of rules. The functional separation of transmission and generation means that there are no bad incentives to favor your own generation if you happen to be a transmission owner.

SMD does not address what I think are the other big restructuring problems: requiring consolidation of RTOs; seams problems; who is responsible for transmission expansion. There are exceptions of course, to everything. Little, discrete DC pipes connecting A and B make perfect sense to me. But general expansion of the AC system is such a thorny issue with so many indirect network effects that it is difficult to think of it as a process under which people can independently think up new transmission ideas and invest in them. It is not impossible, but it is under-specified as currently written.

Who can restructure generation? I think neither a state commission nor FERC should have the ability to tell a utility, "You must cut your company into three parts, four parts, eight parts, you must sell this off." Of course they can structure a deal such that you agree to it, but it has to be voluntary. People like Sally Hunt believe it is more important to make electric generating companies smaller than they are now, but I am less concerned about that.

If just and reasonability is being set by the competitive generation market, regulators can step out of the process. SMD provides liquid, efficient marketplaces. We need to be careful about the criteria and due process we use to regulate entry. We need demand response. Ownership in the US is concentrated by area and may need divestiture. The various munis and public power agencies and the federal government own close to a third of the generating units in the west. How should those units be bid? Should the federal government profit, or should it aim at a modest loss? Should it create the price?

The big advantage of SMD is that it gives transparent spot prices that are needed for the settlement of contracts. Prices should be set by demand as well as supply. We will fight for years about the cause of price determination in California in 2000, but there is no question that inferring from the marginal cost of supply that it somehow is the equilibrium price is nonsensical.

Most wholesale transactions should be at contract prices. I would want to know that any contract is at a roughly fair price of today's price. Beyond trying not to get fleeced, I do not want to deal with the day-by-day distractions of having to watch the spot price, particularly when I might be paying some average price anyway. Should regulators require contracts to limit market power if small customers do not have choice? I think it is a natural evolution of the market that out of fear, people will sign such contracts. I do not know of any particular reason for someone who wants to bear the spot market why they should not be allowed to do so.

On demand response, customers should be metered and priced by the hour. There are some cost-benefit considerations, even though for small customers, the metering equipment may not be worth the effort. Some estimates suggest that if we could get 10 percent of load on meters – and 10 percent of load that is liable to be responsive, it that will solve many of the problems we saw in California.

Marginal purchasers should be at spot pr ices. Full requirement contracts are generally not helpful because all you do is shift the risk to others who will lack the tools to help. Leaving a modicum of your power at the spot price, incremental about some figure, should give incentives, even to small customers. This limits market prices and allows spot markets to clear. California would not have happened if this had been done.

Then markets can be competitive. Distribution companies will buy most, but not all, on contract at market price or historic price. Large customers will have a choice that will provide enough buyers.

Another set of considerations arises if we have complete retail access. We will need much more information from the customers and about them. What will we do about people with no interest in this problem and the problems affiliated with default service? I believe that is not where most of the benefits are.

Beyond the big states and tight power pools, no single state can make a competitive market. FERC lacks the authority to require divestiture, expand transmission, require metering and/or remove these barriers to entry. There are too many actors who are not working off the same script. We need a national vision. SMD is a useful start. FERC has a vision, but no power and not enough staff. The problems may not be solvable without some shift of jurisdiction from the states to the federal government.

Speaker Two

I will talk about some of the flexible features of the PJM market, why they exist and how they become available to customers. Obviously, customers can enter into futures contracts. They can liquidate them into either the day-ahead or the real-time market. They can actually react to the pricing conditions as we come into near term, or can book out the contract against what I call the hub price or some reference price.

Many people do not understand how flexible the self-determination of generation utilization is in PJM. Roughly 40 percent of generators will make their own scheduling decisions, including pumped storage or run-of-river hydro; nuclear power will usually self-schedule because it doesn't want to react to the market. Other gas or other kinds of municipality generators may not care if the market exists; they would rather sell supply. The self-schedulers are price-takers, but they still see the value of that generation coming into the market.

All the bilateral transactions in PJM are financial, facing the spot price as it comes into either the day-ahead or real-time markets. The day-ahead market essentially clears with a transmission system feasibility study. This is fundamental because you really won't clear that market if it is infeasible.

The real-time market operates every five minutes. Generators that are flexible in following the dispatch will set the prices. Generation that self-schedules will just see the prices and become price-takers. If something unexpected happens on the system, the price signal will change and people will see it quickly: when a line switch is out, within five minutes the pricing system will move generation or transactions in response.

The market supports a variety of financials. The key though, is that you do not need to be the system dispatcher; the complexity of running the power system is kept in the real-time dispatch center. The prices sent out reflect the changing system conditions, but the complexities are internalized in that constrained economic dispatch. All of the financial that happen around the market really just react to the spot price.

This is how a financial transaction in PJM works. Generator A in California wants to sell energy to someone on the Oregon border. The load that ultimately consumes the power might be in Denver. We have just constructed a contract path. In the bilateral contract world, hundreds of these contracts occur throughout the system. People do their deals, but the actual dispatch does not worry about that.

Now say that generator A is self-scheduled. It sells its energy forward and wants to cover it. Suddenly, a constraint occurs where Generator A cannot get out of the local area. It needs to be dispatched down, so it exercises its right to self-schedule. The price will start to drop near zero. It can actually reduce that output, buying back its energy at zero and use its financials to deliver it. Generator A ends up serving its load at a lower price by essentially surrendering its right to someone else and being paid for it.

Today in the TLR world, we can't do this, but in the LMP world you can show the price. Generator A sees with its financial contracts that it has already locked in the system. It will get back the revenues, even though it is not actually delivering the energy. At the time of dispatch, Generator A is indifferent to whether its electrons are delivered, or it is buying spot. That is now the efficient utilization will go.

There is a lot of congestion in PJM; it ebbs and flows, changes with time and is somewhat unpredictable. There are thermal, stability and voltage limits. Predominantly in PJM, we have the first two, whereas stability limits are more characteristic of long system like the west. There are some stability limits in New York state.

PJM's five-minute market can convert the voltage limits into a pre-contingency flow limit on a near-term basis. The information is posted on the Web. In the next two years, PJM will implement a real-time stability limit calculator.

Once there are transmission limits, there are options to control them, like reconfiguration. You can cut contracts or you can redispatch. As you redispatch, the prices separate. You lower one generator and raise another, or you could actually dispatch load. You see the signal go out. Then the question is who has the right to use the system. We do not know. The transmission system is a limited resource.

For 20 years, the PJM power pool was constrained. Power comes out of western Pennsylvania and flows into New Jersey. That was the world until 1999, when markets opened up around the country. Suddenly for the first time, energy flowed from the east to the Midwest because that area had some shortages. Today in PJM, there is one predominant constraint path into the DC area. But on any given day, constraints might go north, east and south. There is a lack of predictability.

One concept of transmission rights is obligations versus options. If you think about the allocation process in areas like the Pacific Northwest, where you have the seasonality issue, you can still have a set of long-term rights, but they may vary by season. In PJM, for example, you want a transmission right when a pumped storage unit is generating, not when it is pumping. PJM has an on peak/off peak situation so the generator can get a right when the flow is favorable. surrender the right when it is not, or can get the right in the opposite direction. These are called multi-period auctions. PJM can have a sustained auction over a long period. Within the auctions, there are various granular looks at the system. These may be more fundamental because of the actual sustained patterns in PJM.

A problem with the Pacific Northwest is that is that the market has to deal with the interface boundaries. Suddenly, the dispatch control stops, but the electrons do not – a fundamental discontinuity. This requires inter-regional coordination. PJM and MISO will have some areas under markets, while others will not be. We are designing a procedure to allow the TLR mechanisms to coordinate with the locational pricing mechanisms. Every 5 minutes, PJM will calculate the flow on external flowgates and post it to the NERC IDC so people can see the composite dispatch and how it affects external flowgates. Instead of then trying to cut individual contracts, PJM can redispatch efficiently and help NERC achieve its release. We think this is a positive step.

Speakers Three and Four

In the northwest market, there are three main differences in design from SMD: a requirement for balanced schedules in the day-ahead market; our catalogued transmission rights which are either auctioning or allocation; the special characteristics of the hydro system and its low prices and how those drive the design.

The old story in the west is that we have a lot of capacity because of our hydroprojects. What we are short of is energy. You can generate a lot of capacity to meet sustained peak by dropping water out of a reservoir. When you finish dropping, you wait for inflow to refill and you are done using those generators. We also have a lot of storage and so we describe this as a hydro thermal coordinated system. "System" is not the same as operating a series of independent projects. We not only save fuel through coordinated long-term storage; we also save the costs of capital investment. By coordinating operations, we can produce more firm power out of the system, using the storage in large storage reservoirs such as Grand Coulee, and effectively avoiding the investment in a couple of thousand megawatts.

Because the projects operate interdependently, you cannot simply operate a hydro system on short-term price signals. There are river coordination spans, multiple plants, long-term periods and what's called "a critical water period." If I had the least flow that has historically occurred in the northwest, how much energy could I produce before I run into mud in the reservoirs? It was about 42-and-a-half months before the recent fish constraints; now it is one year.

SMD frames an interesting question. If the assumption that consumers are better off competing because competitors in wholesale markets compete hour-by-hour, that seems to conflict with the northwest's operational strategy to maximize firm power production over long terms through cooperation. That is not to say that the two cannot exist to some degree; we think the RTO's proposal tries to do that to capture some additional efficiencies. But the concern is that we do not want to give up the large benefits from coordinated generation – the heart of the low costs in the northwest.

There is also a lot of flow reversal occurring as we operate the system. From yesterday to today, or on typical days with nothing special happening, we might move generation by several hundred megawatts from Grand Coulee to a downstream project several hundred miles away. One degree of change in temperature in a thermal system does not much affect the output of thermal plants, but one degree of unexpected temperature change in mountain territory moves water down that mountain faster than you planned.

There are three basic things you can do with water: store it, generate it or spill it. If you generate or spill, now you have a wall of water moving downstream, passing as many as 11 projects. You must have a strategy for dealing with the wall of water and the downstream project owners.

Geographically, we are very spread out. For example, Idaho Power's system goes from Jim Bridger to LeGrande, Oregon. If you were to put Jim Bridger in Washington DC, LeGrande would be a little west of Lansing Michigan, about north of Indianapolis. Idaho Power has 3000 MW of retail load – probably less than the city of Cincinnati. Since we have very little load to spread a very expensive transmission system over, we are stingy with how we build transmission. We push the system really hard. We take remedial actions like dropping generators and fully loaded reheat steam units. Explain this to eastern engineers and they think you are crazy.

The system is highly committed. The big problems are the amount of congestion and the perception of a lot of congestion. If you think the system is over-committed and that congestion is an expensive problem, you panic at any suggestion of losing transmission rights. People believe these rights are extraordinarily valuable and that they will face tremendous costs if anything goes wrong.

We have a lot of low prices. Financial people in the east are thermal thinkers. Typically, people look at a hydro system as a fuel saver – its value is the savings in gas or coal. After you talk to them for a while, they realize that coordinated operations displace capital – the O&M from resources that do not have to be built, and the fuel from those projects. The magic trick is that we can release water during the day from Bonneville Dam; sell that power to California as capacity; require California to return the energy off-peak; and charge a fee in the form of energy. Depending on the circumstances, there can be a two-for-one trade – for every kWh shipped south, we get a kWh back. In good system conditions, we can store both kWh in Grand Coulee. We have pumped it up hill about a thousand feet without a pump. This means that we can take capacity and convert it into firm energy that we are short of – only one example of the flexibility that storage gives. Sometimes, we can get that water into Canada. Canada gives us access to 3 treaty storage projects. Other contracts gain access to additional, no-treaty storage space in Canada.

We have a history of trying to make markets work. We have had markets on the West Coast for a long time. We built the intertie that connected us to the southwest. NYMEX picked our system for its first electricity contract in the 1990s. What is new to us, though, are locational prices, and how to integrate short-term thinking without jeopardizing the tremendous value of long-term operational strategy.

The attitude and the perception in the Pacific Northwest is that we have a winner in the form of low prices to consumers, but people are also skittish because what happened in California translates into lost benefits. This contributes to the political concern about adopting new systems that may jeopardize what we have. Like going to college, the benefits are uncertain. People, go but some people do not do too well in life or in college, and yet the costs are pretty certain. The characteristic of having certain costs within some limits and uncertain benefits is a common problem for us, but it is particularly stick because we operate on a base of low prices.

There is a push to preserve as much of the past as we can. I know this sounds to some as though we are Neanderthals who do not want to change, and that is probably a fair criticism. But people in the west understand how this complex business operates and they are comfortable with it.

We have some tiny utilities. To find an equivalent transmission right that makes them feel comfortable that they are no better and no worse is a problem. People are not willing to absorb cost shifts in adopting these new systems.

Some well-organized opposition shows up in many forums. The opponents of SMD and RTO West have hired advertising agencies and are going straight to the public with TV and print ads. They visit the northwest's Congressional delegation, saying, "If it ain't broke, don't fix it. We know we've got a good deal, and we don't want somebody fiddling around with it." A bigger lever is pushing the Congressional delegation to take Bonneville out, which is most of the transmission system. The political resistance manifests itself in design decisions that attend to the needs and fears expressed by stakeholders, which comes back to transmission rights and preserving the hydro coordination opportunities. In the last few months, we have seen some softening and we are hopeful.

Market design has an emotional dimension and is not simply an academic exercise. We are tying to shift the debate to facts, rather than fears. Understanding regional differences in forums like this helps. But some of these fears do not easily go away. Until we get through more detail in SMD and possibly get some operating experience where we see the spot market prices actually being beneficial, we may be unable to let go of some of the trappings of the past. There is also a lot in common with SMD. There are financial transmission rights and an LMP-like congestion management scheme. We will have spot prices.

However, two differences are schedule balancing and the lack of a day-ahead energy market run by the RTO. This means that the RTO does not stand behind buys and sells, where someone can come in short and put the obligation to meet its load the next day on the RTO. Our concept is an entity that manages transmission, leaves the load responsibility where it is today and allows access for everyone. We have an accept-all schedule system and we use redispatch that the RTO will manage to solve that problem. But we do not have a day-ahead energy market that can be used to serve load when you are short.

There are times when we cannot easily move thermal generation into the place where you need energy, if there are unexpected draws on the system. Unfortunately, Bonneville is the easy target and sometimes is encouraged to invade fish constraints or disrupt operations. Then here comes a short schedule; the RTO cannot meet it easily without relying on Bonneville or someone like it. A second bad water year could mean there is not enough energy to meet what will happen the year after. Hydro variability from year to year is phenomenal. You can only store about a third of the year's flow compared to the Colorado River that can store about three years. We cannot easily even out these flows, even though we have a lot of storage relative to other systems. For a variety of reasons, we worry that unbalanced schedules will have an adverse impact on our coordination.

We do think that LMP will offer advantages so that people will be willing to do deals based on those prices, but we think you do not have take the full step of adopting a day-ahead energy market Day One.

Our conservation strategy was not designed to displace capacity, but to save energy. We have been doing it for 20 years. We used to be the masters of demand response through DSI. That stands for Direct Service Industries – the aluminum smelters. We could interrupt load with no notice for 5 minutes, instead of rotating around, so we had a marvelous reserve built into contracts. Recently, the DSI load has been bought out because we are short of energy. The thinking is that the service to the DSIs will never be what it was. It used to be 2800 MW; now it's around 800-1200 MW. It might be worth restoring. We believe there are devices with the right type of load that can provide capacity benefits, translation, ancillary services. Certainly, energy is available and we are committed to make sure the demand piece fits here. The trick is to make sure it meets the qualifications for an ancillary service that is available when needed.

The arguments about the problems we will face have merit to some degree. Today, the proposal is to make this work with balanced schedules; keep the load responsibility where it is; use bilaterals that have been the heart of the Pacific Northwest's strategy for a long time; and create the markets to solve the short-term energy needs. At issue is whether we will get some of the areas in the hinterland to develop enough local ancillary services to make for markets because our geography is large and the size of our utilities is small.

We are branching away from either transmission rights auctions or allocations. We propose a scheme of catalogue transmission rights. We need to be able to tell people that they can hold what they have because people think there is so much to lose and so little to gain. A problem we face is that at different times of the year, generation comes form different directions, so the existing rights have a lot of scope or spread and flexibility. If you try to get an allocation of the rights, you might get a fourth of what you thought you had on some of the major critical paths. We sliced the year down to 24 pieces so that we had on- and off-peak every month and that did not work. Then we went to a 48-slice piece and it did not work, either. Finally we decided to catalogue all of the existing use of the system, and make that non-tradable, to preserve your ability to do what you are doing. Then we will introduce the new FTRs, take the little amount of ATC that we have, and move it out. We want to add some incentives to move some of your existing operations and shrink your flexibility. At least Day One, we give you a way to hold what you have.

We propose to use options, rather than obligations. The option pays credits against what would otherwise be your bill for congestion, largely calculated the way LMP is in PJM. There are two types of options: CTRs – catalogue transmission rights, which make a perfect hedge for the customers with existing rights. They are never exposed and it runs up to real time, our current practice to accommodate the hydro flexibility we have.

For those without contract rights, we have FTOs -- firm transmission options. They are tradable against ATC. The RTO decides what FTOs to sell, because unlike SMD that applies a feasibility test on the rights ahead of time, we apply the feasibility test on the schedules. When we apply the test to a system where 10MW loads have transmission rights flowing between them and 30 federal projects, the system appears to have far more claims than can be managed. However, when the schedules come in, the diversity of the locational loads and generators nets out, so we apply the test on the schedules day-ahead.

There is a problem with defining some other rights in advance, like CRRs. We can accommodate some seasonability because we are a winter peaking system. We can accommodate some irrigation demand. Seasonality has some advantages but introduces the risk that the RTO correctly guesses what FTOs to sell. The logic in promoting the use of FTOs is that those with the highest congestion costs should bid to move them since they are freely portable and unassociated with any particular path or injection point.

Discussion

Question: Is it appropriate to count 100 percent of your capacity as available capacity or should it be rated differently from its nameplate to reflect the amount of capacity that you really believe is there at any given time? Could you offer capacity and energy based on what you really think it is worth into the day-ahead market? You say you do not want people placing unexpected demands. Do you have the pricing flexibility to deal with your shortage concerns?

Response: Nameplate rating is the wrong way to look at this. Our concept is sustained peaking capability, or integrating supply with capacity. The capacity varies with the water year. In terms of bidding capacity in energy, we bid it for what it is worth into the California market at COB, NOB and so on. There is debate about how that price is arrived at, but at times, it is simply the opportunity costs of fuel on whatever is on the margin on the West Coast. There is not a perfect correlation between natural gas prices. Generally, we will look at those prices and predict a day ahead or maybe a week or so. We do monthly and annual blocks and variants, basically on what the market is or what we think it is. The benefit of capacity is to convert it into energy through these exchanges. We do less of that today, but we will sell capacity at market. Many times it does not have a lot of value. We have done these things for a long time.

Response: Today, everyone is required to balance on the last day. This has aligned our resources and load on a company-by-company basis. One concern is that people say, "I'm just going to get 500 MW today from the RTO." Often, thermal generation is behind a lot of transmission constraints. If you just take it out of the hydro, you disrupt the coordination. If the hydro owner says, "Sorry, it is not available now," one of you can be accused of financial or physical withholding. How do you manage market mitigation where you do not have a clear concept of an underlying cost? The cost of doing something today is what you think you can sell the power for next summer. We are cautious and conservative.

Question: To what extent is FERC's RTO West order – paragraph 273 – and the deference it has given to RTO West a good starting point?

Response: FERC has asked for more detail, particularly about how our CTRs will work. The fact that they are non-tradable is still a struggle for us. We do not intend to hang onto or implement something that does not work. We have some years before we actually start operation. I think we have the green light to keep going.

Response: I think FERC has said, "Thank you for the thoughtful progress you have made. We see questions you have not yet answered, and the devil can be in the details in some of these issues. So go forth." We know it is a process. We know we do not have all the answers.

Question: Is the political opposition to SMD willing to accept that this is a good place to start? I have heard little discussion about future energy supply and capacity supply. In the future, most of the new generation in the northwest is coming from merchant plants. And the attempt to always firm up hydropower would seem to contribute to a reduction in reliance on the spot market. You are concerned about more pressure on hydro, but part of the problem is your unwillingness to say no when there is a deficit. Saying no would send a price signal that would reflect the actual costs of the power, including the external costs of the other uses, such as fish, that you worry about. If you say that some transmission paths are 3-4 times over-subscribed, would the right price signal for the consequences of unbalanced load encourage people to balance anyway? Given that the future energy supply is not hydro or from utilities, given that you do not say no when you should, given the oversubscribed transmission paths, why do you maintain that the system is not broken?

Response: The Pacific Northwest's low prices do generate the attitude of, "Ain't broke, don't fix it." Although a lot of stakeholders really believe this, I do not. In my world, the future of generation development will be more with the independents than with traditional utilities. To encourage investment in generation and transmission, we must have a stable market design that people can trust for the long haul. Right now, we are in transition – and in transition to what? We want to move ahead, but we are trying to tow along many of the people who say the system is not broken. The way we chose to say no is, "Show up on the last day with balanced schedules. Do not expect to show up and get it out of the hydro system."

Response: The northwest has long relied on informal coordination by telephone. We think SMD, which operates more under rules of competition, puts this strategy of cooperation at issue. Our question is, how far will coordination be injured by just a simple philosophy that says the better way to produce low cost for consumers is through competition in the short-term markets? Energy supply ties intimately to transmission infrastructure construction. Bonneville is committed to building it to fix the system's reliability problems and to integrate with the new power production in the form of thermal plants produced by IPPs. Here, the issue is project financing. A year ago, I would have said that new people who wanted to integrate resources drove much of the cost. But today, projects are being cancelled because prices are low and people are gun-shy about signing the longer-term contracts that permit the financing. The potential dilemma is that the load in the Pacific Northwest is growing at a slow but steady rate, and supply may not be keeping up. There are other thermal plants that are contributing to the solution, but transmission needs to be built as well, to improve the efficiency of the current resources.

Comment: You can have as much cooperation as you want; SMD allows you to keep score on that cooperation. A friend and I go out to dinner about once a month. Sometimes he pays, sometimes I do. We've never kept score because we are friends. On the other hand, when the substantial resources of taxpayers and others are taken into account and where substantial gains are to be had from actually knowing that you sent me power at night and I sent you power by day, wouldn't it be nice to know the costs? I understand people dislike opening up the subsidies that are inherently in the system by putting a price tag on it. But don't taxpayers deserve to know the value of the subsidies in order to make informed judgments the next time someone wants to build a new plant somewhere?

Response: We will invade our strategy at times when people are in trouble. Last year was a dry one. Did we invade fish constraints to keep the lights on? Yes. On the subsidies issues, credit unions are not subsidized just because they operate for no profit. We pay for all the costs that are invested at the cost that the US Treasury incurs to lend us the money. It makes a profit and taxpayers come out ahead. We pay those back. Some things are a little favorable to a Bonneville, like 85-year depreciation schedules for dams. But we pay that back. We subsidize irrigation, flood control, navigation and other benefits.

Comment: Some people get more benefits out of the money Bonneville spends than others.

Response: Bonneville's mission was to produce benefits for northwest consumers, and that is defined geographically. We export power to California at market and credit the revenues against the northwest. Generally, that accrues to the benefit of publicly owned utilities, but also privately, to IOUs that serve residential customers, such as small farms.

Question: Do you think that the existing system could efficiently and economically accommodate the market of the future? If BPA builds transmission, that simply means it has 80 percent of the transmission and 40 percent of the power. Without at RTO in which BPA participates as an independent dispatcher, the concerns about market power and market manipulation exist.

Response: The word, "broken," presents things as black and white. Broken implies "not usable." To me, the issue is can you improve on current practices by adopting some of our policies? Administrators are trying to make the RTO work. I see three major benefits of an RTO. The first, which does not receive much attention, is that you consolidate control areas and then you have lower reserve, for instance. The second is that eliminating pancake rates and sinking transmission costs convert a system from toll roads into freeways – an improvement in just the recovery of fixed costs. There will be some modest benefits gained through some of the market structure, although they will not be as large as those in a thermal system where fuel costs are relatively high. The third benefit is innovative thinking. LMP improves the quality of information available. What will people do with better information? But to say that this panacea will solve all of our problems is incorrect. We have to get supply from somewhere. Our assumption is that it will come largely from IPPs. We do not defend the position that nothing is broken. We assume we can improve things and that is why Bonneville, at least, is in the game.

Comment: Today's market structure is not a good platform to encourage independent development and transmission expansion. We have a lot of baggage to bring along. We have had to say, "Well, we can't get all the way to the pure, clean model in one leap." We need a starting point that lets us hang on to some of the features of the past along the way.

Comment: We should make sure that we preserve the benefits of coordinating the complicated interactions of the hydro system. SMD is actually a tool to enhance, not preclude this. Should FTRs be options? I think the answer is both options and obligations. "Use it or lose it" is a mechanism for reintroducing physical rights because you have to match up your actual schedules with your rights or you lose the money and you have all the associated inefficiency and complications. Balanced schedules are more complicated because I think they make markets inefficient, reinforce market power and create incentives for gaming, such as Fat Boy. The problem of having people make sure they are responsible for load is another matter and it will cause difficulty. Texas and California are good examples. CTRs are a hard problem without a simple answer. How do we get over the hump of what everyone thinks they have today and what they will have in the future? The answer mostly has to do with equity and perception. You will have to struggle through that and interact with FERC in the process.

Question: Are options a back door for physical rights? We tried abandoned them because they did not work; one reason was prorating downward to accommodate the claims on the system that look like they exceed the space. They do not actually do this, but they look bad. We adopted FTOs that can be used against any schedule. We first look at ATC. An FTO is associated with an injection withdrawal point, but is useable for anything else in the system. I could sell it to you; you could buy it from me. It has no hoarding features.

Comment: They cannot be done bilaterally.

Response: That is our proposal.

Comment. Either do not use it and lose it, you get a check, or use it or lose it and get no check. If you do not get a check, you have to match it with a schedule and that makes it a physical right.

Comment: You do not have to match it with a schedule that matches the way the FTO was defined.

Comment: You can put a schedule on it and get a credit for having your schedule in. You cannot just sit on it and wait for the market to clear and then get money.

Comment: I do not sit on it. I offer it into the reconfiguration auction. Then I get the cash and do not have to find someone else to buy it from me. The RTO will take care of that for me because of the complications of the auction. You cannot hoard FTRs. You cannot manipulate price by buying them.

Comment: Do options and obligations together and let the market decide what it wants to do.

Comment: Other people pay the generator to reduce. It buys spot and if its transaction goes away and if the right goes away with it, it all unwinds. We decided the simplest way is by definition: if you did not pay before, you do not pay now. That created a split between an FTO and and a CTR.

Comment: Initially, the New York ISO proposed a physical allocation of rights to congestion across major interfaces, more or less allocated by megawatts. The engineers had to convince themselves that the financial right was not as good as the physical right – a concept foreign to the way engineers operate the system. Next, the financial rights were grandfathered in proportion to the megawatts, and were not physical. Then the transmission owners actually traded in the market. Remember that one difference is that all generation is divested in New York. They agreed to this because the market players did not want to hedge service and compete with the TOs if they could not buy the rights. The TOs agreed to put them up for auction, but wanted to be able to bid. The compromise was that the TOs could bid. In other words, you have an incentive to bid the price high, and if you set the auction, you take money out of one pocket and put it in the other. Now, if you do not need it for supply, do not even bid. Let the auction work, and let your revenues roll in from that. People get nervous about whether they will get reliable power. Can you go through a multiple transition and trust that the system will work? You can get there.

Response: The New York situation of generation divestment and separate ownership has not happened in the Pacific Northwest, with the exception of Montana. The idea that you can bid into auction and get money back has been unsuccessful. Who does the money go back to? Seattle would get it all, if you prorate it. The small utilities would worry about lacking the creditworthiness to bid into an auction like that.

Response: There are dozens of small distribution-only entities, some with only 100 customers. They look to us as protecting them. This is about equity, but also a legacy of 60 years. It is also about the fear of people who lack the capability to even participate in this kind of discussion. They lack the staff or the money to pay for the expertise. There are groups like the Public Power Council that work together that do hire expertise. But they are entirely beholden to a few individuals. It is tough to think that they will have to make decisions about bidding, when they are worried about serving the local farmers and keeping prices low.

Comment: Everyone does not have to worry about arbitrage and day-ahead, or whether it is real-time.

Comment: We went to a CTR because if you do not know anything, life will look the same. But people who are insulated from having to make decisions and develop the expertise fear the effects will be there indirectly in the form of higher Bonneville rates.

Question: Anything can work as a starting point, because the dispatchers will keep the lights on, no matter what. The real questions to ask are: Is your design sustainable? Does it deliver customer benefits? Does it encourage helpful new investment or private investment?

Response: A philosophy of continuous improvement needs to be the guiding philosophy for design. Changing the design is a sign of health. A lot of customer benefits are quantifiable, but there is softness because we do not know where innovation may take us. Our strategy is to keep prices low. The issue of new investment will be debated more in terms of the best business strategy for developers: develop merchant plants and take the risks, or find long-term contracts where the risks are split between buyer and seller. Let both business strategies play out and do not confuse the business strategy of a developer with SMD. Market design should allow us to be a Nordstrom or a Wal-Mart, to go short or long.

Response: Do not be an impediment to investment. That is where we are today with a market design that is simply unstable. Today's scheme of physical rights might be replaced down the road. All by itself, that is an impediment to investment.

Comment: You can keep the lights on through command-and-control, or you can show prices where it is valuable to have generation. You can use the market signals to drive investment. Some people in the east have tried different things. We have some scars, but maybe that can be the beginning of a dialogue.

Question: An ultimate design test is if adequate infrastructure is built in a timely fashion. A concern about SMD is that it could go further to make sure that the transmission business is more of a stand-alone job, like what has been done in Texas, where transmission is being built on time, maybe more than anywhere else in the country.

Response: Expanding infrastructure in a timely fashion is a difficult problem, but it could be a mater of sending the right signals and putting together a structure that could approve the right set of investments.

Comment: When Texas had an ISO that defined where transmission was needed, the TOs did not have to worry about the effects on retail customers. Their job was to build a network to serve the entire grid.

Comment: Separation is the cleanest way to say, "Look, that is your only business; that is your only constituency."

Comment: The Texas legislature told companies, "You have a choice. You can spin it out into a separate company if you like, or you can put it into a separate company under the holding company umbrella with its own books and records." That was a choice given to companies, that I think is the appropriate choice.

Question: Who is underwriting the opposition to SMD? Who are the stakeholders that feel they have something at risk with the changes you propose?

Response: Loosely speaking, our public customers.

Question: How does RTO West look at pricing if the through-and-out rates disappear? What does that mean for cost shifting and recovery of revenue requirements?

Response: The basic concept of the RTO pricing for the fixed part of the transmission costs is to synch them to loads on a company-by-company basis so the customers see the same volatile rate. Say 20 percent of our revenues come from short-term sale of non-firm transmission or surplus firm from through-and-outers historically. Essentially, those costs are exported into California. To avoid a cost shift, we adopted an export fee – that is not the term for it – for through-and-outers, the only incremental toward fixed costs that we have. The hope was that we could work out a reciprocity agreement with neighboring RTOs to convert that into a transfer charge, so it would be equitably calculated and reflect historical payments to put people in the same position as before. The through-and-outers in the same situations see no difference, but an issue for us is that still looks like an incremental charge on fixed costs. Synch as much of the transmission cost to load as you can, so that all parts of the system look like a freeway. The proposal today does include an export fee to keep the cost shifts squared away to represent the revenue we used to collect from short-term transmission sales.

Question: What if we cannot implement RTO West? What are the consequences of doing nothing?

Response: The lights stay on. I think prices will be low. But I think we will see some problems; maybe generation will not get built as fast because of trade barriers. Maybe it will not be put in the best location, which will lead to mandated approaches that tweak transmission without the benefit of price information. I do not know that it's such a dramatic difference for the Pacific Northwest. We are talking about relatively modest gains on things.

Response: If the opposition wins, maybe FERC forces the IOUs to do something like SMD, but Bonneville does not have to do that. Then you have a seam that is not a seam.

Question: Are you better positioned with or without RTO West if there is another drought or California crisis?

Response: Droughts are supply issues and we plan ahead for them. To me, it is not intuitively obvious that failing to adopt RTO West and SMD causes dramatic changes in and of themselves from these catastrophes. They happen in the course of our business, anyway. Floods are another: Portland, Oregon, came within 6 inches of being underwater in 1996.

Question: Public power and non-jurisdictional entities own about a third of generation and a significant amount of transmission in the west. If they opt out for any reason, can you implement anything that really resembles SMD? How do you encourage them to opt in?

Response: The bulk of the entities that cause the problems of the CTRs are small. From a wholesale market standpoint, they probably do not matter much, but they create enormous problems in terms of equity.

Comment: That suggests that there is scope to buy them out or without explicitly doing so, offering contracts that look good and have competition provide them this sort of service. It is hard to picture if Bonneville opts out of the system.

Question: My impression is that the economics is still going west and the finance is going east. From an economic perspective the goal is still to move toward the market end of the continuum. From a financial perspective, the desire is to move back to rate-based rate-of-return, with as much gold-plate as you can sneak in. From an economic perspective, there is still a strong interest in further unbundling. From a financial perspective, now there is a much greater risk moving back toward reintegration, including among some companies that have unbundled. How do you reconcile the 2 worlds?

Response: Time. If independent generators now lack the financial wherewithal to construct new units because they lack access to the capital markets, nothing gets built. When nothing gets built, it gets expensive. When it gets expensive, someone will advance the capital. The notion that pain is involved and that regulation is somehow more comfortable is absolutely true. The tradeoff is, do you want a comfortable, slightly more expensive life, or a somewhat more turbulent, cheaper life?

Question: How much risk does the distribution company or default provider face from simply leaving direct access open, even if the expectation is that there will be relatively little activity?

Response: That no one will take it? There are many costs to creating retail access, and it is a question of whether all the costs are worth it. If enough people do not want it, it is wasted money to create that system.

Comment: It's cost-benefit.

Response: It is not a bad idea, if you can make it work.

Session Two. Standard Market Design and the States: Are They Preempted or Are They Enabled?

The state regulatory community appears divided over the implications of FERC's SMD proposal. Particularly in the south and west, SMD is viewed as a massive preemption of state authority. Mandating the de-verticalization of utilities limits their ability to appropriately regulate the retail market and protect end-users. Others believe that the proposals for demand-side bidding contained within SMD are indications that the federal government will assume command over all state retail jurisdiction. States with low-to-moderate rates are fearful that SMD will undo local management and regulatory efforts to maintain such levels and native load customers may lose the special reliability benefits they have under the existing regime. They see SMD as a one size fits all mentality that fails to recognize the regional diversity in the nation's electricity markets. Conversely, the northeast and Midwest see SMD as enhancing retail markets by opening up access to a broader geographic and technological array of resources. Ironically, some fear the resource adequacy requirement of

SMD may actually impede the evolution of retail competition. Robustly competitive, efficiently functioning electricity markets, they suggest, require the kind of cooperative federalism implicit in the state advisory role contemplated in the NOPR. Which sets of perceptions are correct? Just how preemptive, if at all, is the SMD proposal?

Speaker One:

The enabling legislation for both FERC and the states did not envision the world of the Internet; real-time communication; superconductor technology and the other obvious add-ons to transmission; distributed generation; software that better manages demand-side programs; real-time meters; or environmental problems and the need for mitigation. What is did envision is the monopoly model forever; state markets; unempowered customers; abundant and unlimited hydropower; and no mitigation costs.

With or without us, the world has changed. Like it or not, the opportunities to leverage the local advantage because we have regional markets are real. Markets are integrated and interdependent, yet we are not leveraging the technology that allows us to use existing assets more efficiently to address many of our environmental issues more sustainably than the Band-Aid approaches we have today.

There are growing costs of mitigation and a depletion of the wonderful hydropower resources that the West enjoys. There is growing inappropriate and non-economic allocation of resources that ultimately, are borne by customer classes of all kinds. Some of the increasing costs of power quality disturbances and the inefficient allocation of resources are being passed on to us in the cost of our cars, refrigerators and the like. We have incorrect economic signals.

Faced with the $100-billion loss of market cap in the energy sector in the last six months, this isn't about what we do based on all jurisdictional models, but how we can create an energy market that takes advantage of the investment that is there and fixes some of the problems I think we can't deny. How can market participants, regulators and smart people effectively transition these markets to leave our legacy for the future? I remind people that FERC's SMD NOPR is a draft. Its evolution is illustrative of a system that is more inclusive than any other process in government that I've ever seen.

Let me tell you what I think SMD does not do. It does not intend to replace state responsibility or accountability to customers in any way; it does not envision; it does not intend to enable. It does not intend to do anything about retail markets. If a state wants to undertake retail restructuring, good, but I would not do it in this marketplace because I don't think we have a wholesale market that can support retail competition.

SMD was not intended to replace state authority on either resource adequacy or demand-side programs. Wisely or not, it does set a threshold in resource adequacy, because there are some regions that were not looking out for the long-term resources necessary to support growth. It is a state issue, but increasingly as we look at regional markets, a regional issue. Let's find a solution that satisfies state responsibility and addresses those regional needs.

SMD was not intended to replace existing demand-side programs, nor to replace the authority of states to implement whatever programs there were. It was not intended to be an intrusion on the ability of states to set rates. That is clear from the Supreme

Court and from the understanding that transmission is interstate. Unless and until we confront that head on, we will not get the investment we need. We're ten years in the hole now. I dare say that doubled in terms of the investment in this in the last six months.

SMD was not intended to cut the states out of the planning process. On the contrary, it tried to create some new models where states could bring their needs to the regional table and resolve issues in a way that works for local communities – but remembering that there is no denying these markets are regional.

SMD did not get into the issue of siting, but referred to the National Governors Association's recommendation on multi-state entities. Someone might want to look at pipeline siting and see if you can incorporate it into the regional model. We need to resolve siting, which is probably the biggest barrier to developing a strong, robust infrastructure for the future that this country has.

While we look for new institutional models, markets, needs and the priorities of both the states and FERC will evolve. Whatever institutional solutions we have, we don't want to make them ineffective by virtue of creating an instant bureaucracy.

SMD is in fact a transition set of rules to get us to a place where markets begin to work. If we learned anything from California and from a couple of other disasters, markets do not happen overnight, particularly when you are starting with an entrenched monopoly. You need strong parental guidance along the way.

You then need a mechanism of deciding when in fact the market forces are beginning to work so you can withdraw some of the bests and suspenders rules that we have built in standard market design. I repeat that reality has changed because technology – something this country does well and leverages well – has moved us to a different place. Let's move our economic and jurisdictional models in response, without losing sight of the common goal – whether in wholesale markets or at the state level – to add value for the customer.

The past was a great model for its time, whether in public power or monopoly IOUs. But it's time to keep what we did best, but build for the future. We are building a model that will attract investment back into the marketplace and that will work in the future. My job is to make sure that there is sufficient commodity and a road to get there. I think we need to push the envelope. I don't think it's about who has power and who does not. I think it's creating what works for the future.

Speaker Two

In response to the statement about reality having changed, some of it has. Certainly, we have a wholesale market and movement toward a regional transmission organization, and we have some new technology. But a lot of the reality is that at least half the states in this country still have vertically integrated utilities and cost-of-service ratemaking. Southern states that would like to retain their very low-cost generation have chosen not to go to retail competition. In other words, there are some practical realities in the states that suggest we need to find a way to keep the benefits we have. By contrast, the parts of the country with higher electricity prices that they would like to lower ought to be able to do that. How do we harmonize these objectives and needs? I think it's fair to say that SMD probably fits much better in a retail competition environment than in a vertically integrated one.

I think the key to resolving this is whether FERC can follow through as it articulated in its RTO West and SeTrans orders, to accommodate regional differences through the appropriate RTO proceedings. How you view SMD really does depend on where you sit, relative to your retail rate design: from that standpoint, you view the provisions in SMD either positively or adversely. I think that the customization and regional crafting of regionally specific and appropriate market design rules is where we need to head. I appreciate FERC's willingness to accommodate some of these regional differences, but the devil is in the details.

Retail ratepayers are entitled to the protection that state regulators are obligated to provide under state law, such as continued access to the transmission service and system that they have paid for, as well as continued access to the low-cost generation. For example, in my part of the country, 70-80 percent of our generation comes from low-cost coal and nuclear that will not be displaced by merchant plants. Since the merchants will not be competing with the majority of our rate-based generation, we need a mechanism to continue to have long-term access to those generation reserves.

The provisions of SMD that most concern us are: whether native load can continue to have guaranteed access to the transmission service; the corresponding regulation of the transmission component of bundled retail electric service; generation adequacy, demand-side programs, prospective generation and transmission planning; making sure that the costs of services remain reflected in the generation rates; and market volatility or market prices due to the inability to have access to the transmission service.

A special concern is the allegation of discrimination in SMD that essentially assumes that a vertically integrated utility must first serve its native load customers, which is, by definition under state law, discriminatory and leads to the assertion of jurisdiction that FERC has made in its SMD. That needs to be removed from any final SMD rule.

I think that we can have different market design rules in different parts of the country that accommodate the different rate designs, paradigms and regulatory models, but keep some common things that might form the foundation. As FERC moves forward with another iteration of the rule, and with the regionally specific RTO proceedings, I hope we'll be able to see those accommodations in the final orders.

Question: Are you maintaining that because of the vertically integrated utility's obligation to its customers, there is a connection between SMD and federal assertion and jurisdiction?

Response: By virtue of the vertically integrated nature of those utilities and their obligation under state law to serve their native load ratepayers and give them a preference, that is per se discriminatory and thereby results in FERC's ability to assert jurisdiction under the Federal Power Act. It would make more sense to look at the changes needed to accommodate effective competition in the wholesale market from a practical standpoint, as opposed to trying to use the discrimination angle.

Response: I think there are various interpretations of the discrimination piece in the SMD. Yes, native load protection is important, but I don't see anything in FERC's SMD that would in fact encourage the low-cost power that you enjoy most of the time – not at peak, probably. Indeed, some studies show that lower-cost power at peak might be available to serve your customers in a truly open market. The point of discrimination is that there is evidence that says that vertically integrated utilities have used their obligation to native load to reserve transmission in a way that makes it inaccessible to others for that purpose and not to serve native load. That is an important distinction and I think there is a way to manage through that. I think there is also a way to protect native load customers for the low-cost power that they enjoy. PJM has vertically integrated utilities that have served native load efficiently with the lowest-cost power that they could get.

Comment: Back in 1997, a vertically integrated utility joined PJM because there was literally a "do no worse" scenario. In other words, because of the use of FTRs – now CRRs – it would at least be able to deliver the generation it owned to its load at the cost of the generation. That was guaranteed because it built the generation; had the transmission; had the load. It knew it could also do better, but the guarantee was it could do no worse. If there was cheaper generation available for sale, it could do better, or if its generation was of value to someone else, it could do better. That is the heart: you're guaranteed the ability to deliver your generation, whatever price that you've bilaterally contracted for that you own, to your load at that cost of your transmission system.

Speaker Three

There may now be some differences of opinion between FERC and most of the states as to what the SMD NOPR says. I think the fundamental premise of the SMD is that the vertically integrated utility has an obligation to serve under state law, and that's the case in 35 states in the country. Having preference on the transmission system to deliver it s generation to its load by its nature is inherently discriminatory, even though the consequence of that is to assure to its customers a reliable – and the NOPR even says this – lower-cost service. So you have a situation where the ratepayers of that utility that have bought or are paying for the generation and the transmission and distribution systems now are considered to be discriminators. The question is if it is undue discrimination when that is being carried out pursuant to statutory obligations under state law.

If, ultimately, it has the authority to do this under the federal supremacy clause, the SMD NOPR is essentially overriding the statutory arrangements in two-thirds of the states in the country. You can have a differing vision of what kind of paradigm is appropriate. But FERC says that the market-based system is preferable to the cost-based system. NOPR disrupts the ability of states like Washington and many others, to preserve a cost-based public service model for electricity. That is the fundamental argument.

The rest of NOPR flows from that premise, that because this is inherently discriminatory or a per se basis, therefore, the whole panoply of rules and the structure that is then created follow. NOPR says that a vertically integrated utility can have CRRs and can bid that back in and will thereby be able to preserve its preference advantage. It seems rather curious. If the argument is that the historical arrangement is inherently discriminatory and that the vertically integrated utility can bid infinity to assure that it gets access to the necessary transmission, there is a bit of a problem with the state tax laws about gross revenues and how to deal with them. In any event, you can bid infinity. If that's the case, isn't the end result the use of the CRRs historical? Are they forward-looking? Are they going to be auctioned? Those complexities aside, if the result is that the vertically integrated utility is left in the same position, isn't that a continuation of the very discrimination that FERC says is undue?

What is the CRR supposed to be doing? If the vertical utility has nothing to worry about and is left in the same position, why are you doing this in the first place?

It seems to me that there is a sweeping, unprecedented assertion of jurisdiction over major elements of retail electric service. The principal question is who should be able to decide appropriate retail policy for the states? Retail policy for electricity is pretty close to air and water in its essentiality. It involves public safety and welfare and a state's fundamental police powers that protect citizens within the context of an appropriate policy that can assure low cost, reliable power that meets future load growth requirements.

If resource planning, demand forecasting, demand-side management, the ability to ensure that transmission is available to meet retail service obligations are not preempted – and I am not suggesting that they are – they are surely intruded upon by what is now intended to be put into place by the ITPs. The RTOs are voluntary. FERC is concerned that the process is going too slowly and that we don't understand just how it will turn out. We'll do mandatory ITPs instead, and so we'll get there anyway. At a regional level, ITPs will assume panoply of responsibilities. These institutions are yet to be tested. What are the benefits, risks and costs of proceeding down that road, when currently many states are comfortable with how their retail customers are being served?

A mantra that has been stated many times is that electricity is not just another commodity. It has enormous inherent political overtones and is too important not to be politicized. When I say politicized, I mean that in the best sense of the word: the public policy oversight of the process. FERC is aiming to remove any ability for the political system to oversee this process because the transmission boards will be independent of any kind of state ability to influence the process.

The issue of jurisdiction of transmission service is of interest. For example, in Washington, public utilities – primarily Bonneville Power Administration – have 76 percent of the transmission assets and the IOUs have 24 percent. Eighteen percent of that is bundled retail. Currently, FERC has jurisdiction in the wholesale market over 6 percent of the transmission system. In the entire West, when the public utilities are deleted, FERC has 18 percent of the wholesale jurisdiction.

Bonneville now participates extensively and voluntarily in the evolution of the RTO Northwest. If for whatever reason, Bonneville were to founder, someone not in an RTO will have to transfer control of its transmission system to an ITP yet to be created. Does the SMD require that in order to meet the reciprocity requirements that are built into this, and the comparability, Bonneville must transfer its transmission assets to an ITP? I don't think the answer is clear.

Bonneville is an enormously important public asset. Large chunks of the population in the Pacific Northwest would not be here today, but for the benefits that Bonneville has provided for several decades. Its inexpensive power has been the engine for the growth and vitality of the economy: the Pacific Northwest uses more power per capita than any other part of the country.

The Pacific Northwest Power Planning Council, appointed by the governors of the four states, oversees Bonneville's resource adequacy and growth. The northwest's Congressional delegation is intensely interested. There is interaction between Bonneville and the states' PUCs. Note that it is a system that seems to have worked remarkably well. But the transfer of public assets to an independent, non-profit, private board answerable only to FERC does not go down very well in the political context of Washington in particular, and the Pacific Northwest more generally.

I cannot identify a single organized group in Washington that supports FERC's SMD NOPR. All of the western governors, with the possible exception of Montana, oppose it, as do states' attorneys general, with a couple of exceptions. The entire northwest Congressional delegation opposes it, and with some exceptions, all of the western commissions.

Question: Do you set the transmission rate that the transmission users pay?

Response: Yes, for bundled retail.

Question: Oregon has never set a rate for what the utilities it regulates charge for the use of their transmission. How are those costs determined in the state of Washington?

Response: Say a utility has built transmission to deliver its generation to its load. The cost to build the transmission is built into its rates.

Question: But in the Pacific Northwest particularly, very few utilities are able to supply their load without utilizing transmission owned by someone else.

Response: Or they have bought access to the transmission system.

Question: Who sets that rate?

Response: Where they have bought access, it would be the cost of the purchase of that access to the system.

Question: Bundled retail is what states allow in rates to cover the cost of transmission. My point is that the rates that someone is charged for the use of transmission are set by FERC, not by the states.

Response: States have not spent any time looking for innovative ways to deal with this issue. Bonneville and WAPA set the rate when you buy bundled transmission from them. If you buy from another FERC-jurisdictional entity, FERC sets the rate, but the state sets the final rate. If a utility that owns its own transmission wants to play with that rate by moving something else around, it can do that.

Question: Are you talking about only the portion of the utility's own transmission, or about the total cost of transmission that the utility incurs included in rates, because those are different.

Response: I generally agree with that assertion.

Speaker Four

I think stakeholders are simply reading too much into FERC's SMD NOPR. I think they are jumping to – if not unreasonable – then clearly unreasoned conclusions. Discrimination is a perfect example: just its mere mention conjures up all kinds of significant problems and interpretations. I think the entire essence of the SMD is foregoing discrimination access to transmission. I believe that a lot of the unreasoned conclusions derive from a predisposition among many people and commissions to reject ideas that are either not understood in the context in which they are intended, or they contrast with ideas that are basically philosophical attitudes that say economies, for example, have strict boundaries that are defined by state lines. A quote from a recent issue of *Public Utilities Fortnightly* stated, "I believe SMD in its current form is the most detrimental regulatory proposal I have ever seen. SMD is a FERC-created effort to fabricate an artificial national market."

Most governors, attorneys general and legislators don't understand this stuff at all. There's not a governor in this country who will read the SMD NOPR, or understand it. I think what we really want to do is carry out a public policy that will benefit everyone in the aggregate. I think the same can be said nationally. To the extent that there are losers, maybe it is because those who are protecting their turf do it in manners that are inefficient. Take away the inefficiencies and they become losers. Take away the inefficiencies in the aggregate and perhaps there are more winners.

We regulators have one job: shift costs, reallocate resources and redefine subsidies. That is what FERC is trying to do to enhance competitive markets for electricity. The struggle over jurisdiction and the rhetoric shroud the real issues. First and foremost, SMD is about eliminating discrimination in the market for electricity with respect to access. I do not think it has much to do with the retail end of it for vertically integrated utilities.

Let me also go out on a limb and suggest that the most important single force embedded in FERC's SMD NOPR is putting the ITP in place. I wish I could be that ITP. I wish I could own all the transmission in the US. I could manage it and I wouldn't discriminate. I'd collect tolls and even let FERC give me a nice rate of return.

If we can get to that point, I think there would be many winners. Could there be a debate over an ITP? Is there something so economically objectionable about it? I don't think so. Maybe someone can raise an argument that there is a jurisdictional problem, but I am not quite sure what it is. Every time there is a fully bundled retail rate, somewhere in it there's a strong possibility that there was a rate paid for that transmission that was approved by FERC. In reality, the rates are so small in comparison to everything else we pay at a bundled rate, that I think we are overstating the impact on the relationship between wholesale and retail. If a state argues that it has lost a certain amount of authority over retail markets because transmission rates are uniform, I conclude that it really hasn't lost a whole lot in value.

In terms of general markets, there are some significant gains that can be had: the larger number of load-supplying entities, the more discipline there will be in the greater market, and therefore we do not have to place the kind of emphasis we see today on overplaying the notion of market monitoring.

In the final analysis, if we blend the notion of the importance of an ITP at the top of a very large competitive market, then other important issues appear less compelling. In turn, this takes the air out of many of the so-called jurisdictional arguments -- for example, resource adequacy. In fact, with an optimum-sized market, resource adequacy requirements can take care of themselves.

Demand response has elements dating back to integrated resource planning. One that has emerged is that big industrials on interruptible contracts can sell their surplus power into the wholesale markets and that those contracts have always been a state purview. If those companies sell into the wholesale market, what have we lost? It is an issue that can largely take care of itself if there is a great market with an IRP at its top.

If we find that there are inefficiencies that push us off path, or market power raises its ugly head, then we can take care of them. But let us enhance the standing of an ITP, its pricing and scheduling mechanisms and collateral operations like ancillary services, which I read as the objective of FERC's SMD NOPR.

And let us not use our powers of resource allocation to salve the states that feel their principles have been trampled. If certain states and regions are unwilling and unready to accept the pursuit of non-discriminatory access, let them go, FERC. Those who choose not to fall in line will find their markets isolated, unsustainable, and the first to let them know will be their economic development directors.

Discussion

Response: Quite a few of us do endorse the effort to make wholesale markets more competitive, and have no problem working in the context of an RTO proceeding. We can make many things better with the existing system. But a key point is that guaranteed, long-term, permanent access to transmission capacity for native load ratepayers is absolutely essential if they are to receive the benefit of the low-cost generation they have paid for and that is currently embedded in their base rates. If low-cost nuclear and coal will be around for 50-60 more years, but you don't have a guaranteed ability to get that generation to the load through the transmission system, you subject yourself to price volatility, reliability problems and so on. That is a key concern. We need to change the CRR allocation auction sales in FERC's SMD NOPR. When you are subject to an auction bid, make sure that the states that want to retain vertical integration, generation and base rates have the right to keep them.

Comment: The statutes that the parties are working on at the federal level are 50 years old and do not really contemplate where the majority at FERC wants to take the nation. This plays out as a jurisdictional debate, but it's really a classic American disagreement about how one of our core industries ought to be structured and operated. It is good that we have those debates. While some parts of the country are on the way or there, it will be a monumental job to move the parts that are not to SMD. Let us restructure the Midwest and get California restructured so that the market makes some sense. Get some experience so that we do not redesign and redesign at tremendous cost. If it works well and produces savings for ratepayers, the rest of the country will follow. There is no reason to force people who either do not see the light, or see the light better than others to go in this direction, particularly when the merchant industry is in tremendous distress. We will avoid a tremendous amount of litigation that FERC stands very well to lose, because it is a close call whether FERC has the legislative authority to implement SMD.

Response: SMD is not really about transmission but about dispatch. The dispatch is generation to retail load. Win or lose, you will be in litigation. I think we get there by doing it in the majority of the country that is read, letting others percolate along and learn the error of their ways, if indeed they are wrong.

Response: Frankly, the development and evolution of RTO that acknowledge regional differences and are moving at different points gets you there as well.

Comment: To date, there have been market power problems in both the restructured and un-restructured markets. I think that you shoot yourself in the foot forcing Washington, Alabama and Georgia to do something that they do not want to do, particularly when the experience has been mixed.

Response: Allowing different regions to proceed makes sense. PJM, a tight power pool, has been around for about 70 years. The twelve states and the District of Columbia that have restructured have voluntarily ceded jurisdiction to FERC by disaggregating their system. They did this voluntarily because they saw it was in their interest. FERC now will coerce that result. It will be litigated for years.

Comment: There is no evidence in other economic models that SMD will work itself out. It requires leadership from FERC. It is much like the Interstate Commerce requirements of the US

Constitution, because of the concern that everyone will choose locally to do something which is in the aggregate devastating to the economy. We can't afford to do this again.

Response: If you believe that, then you have to convince Congress to give FERC legislative authority.

Comment: Congress asked FERC to comment on various aspects of this year's energy bill, including whether FERC needed more authority. FERC made it clear that it has sufficient authority, but if Congress wanted to give more, that would be fine. FERC also said it wasn't looking for siting authority. Focusing on the jurisdictional fight or on SMD generally may have distracted the West from identifying the problems that do in fact exist. Some problems identified in FERC's SMD NOPR aren't terribly important in the West or in some cases do not exist. Others are very powerful. On a region-by-region basis, develop a structure with good decision-making rules and use the structure to identify the strategies to identify and address the problems and then you implement. My goal is to accept a fairly high level of jurisdictional indeterminacy, and focus on what each of us does best and on where the authority gaps are. We can't punt. We did that in telecom, where there were very few substantive differences between the FCC and the states on wholesale issues. We worked closely in developing the wholesale rules but put off the jurisdictional issue to the end. When I cross-examine people in New England or the Midwest, they say the finding of undue discrimination is important because they need it. There is commerce clause authority for the federal government to act in this area. Authority that was granted in the past may be inappropriate to the markets of today, but it is less clear that the existence of outdated authority is itself authority to move, or whether we need new authority. Is it a national security issue? It may be. Is it a question of systemic political failure, such as the civil rights movement where, obviously, there was a need for the national government to intervene? Is it a question of economic externalities flowing out of the southeast into other areas? That is probably the best argument for going forward. My pitch is for a thoughtful development of clear, regional governance and decision-making structures that include FERC working with the states in a more articulated, cooperative federalist model. There is progress in that direction, as well as in dealing with the substantive issues in the wholesale market. It is an important and interesting discussion to have.

Response: I agree that if you take the situation in each individual region and ask what is broken, what needs to be fixed and how to make wholesale markets better, regional coordination and planning achieve that. That is the starting point. There will be different discussions in different parts of the country. The foundation will probably be the RTO proceedings. To avoid more time, trouble and litigation, I'd like to see SMD morph into regionally specific discussions in the context of RTOs.

Question: What would be left of SMD if FERC backed off the jurisdictional issue?

Response: Not much. It would probably require a new rule to address the parts in it that are not premised to the whole rule.

Comment: Sally Hunt says the biggest problem in this country is the 50-plus-1 jurisdictions. She pointed out that we've been at this since 1992 and frankly, have not made a lot of progress. We should focus on the design elements that will make a market work. We can argue from now until we are all in a different job about what is broken. What can we do to leverage the opportunities today that were not there 25 years ago? Let's cut to the chase, because we have been using resources that would be better utilized to serve our customers.

Question: With respect to jurisdiction, are we talking about turf battles? What are the economic impediments to moving ahead?

Comment: When FERC held its first technical conference seven years ago on open access for the tight power pools in the northeast, we proposed some crazy ideas at the time, like LMP and FTRs. We debated some of the concerns expressed today: maintaining the ability to get the generation that we'd built to our load, using the transmission facilities we had built. It took a lot of dialogue, but once grasped, it becomes more comfortable to move forward. For example, if people want to retain the model of a vertically integrated utility that owns generation or contracts bilaterally with generation to serve its load over transmission facilities in which it has investment rights, they are no worse off. And they can only be better off by accessing other generation or being able to sell generation. In time, we got the support of our state commissions. Less than a year later, FERC turned down LMP as the model for our market. Eventually, we received approval, and we've seen generation investment that is market driven that has gone to the right locations on the grid. I am confident. I also know that you don't have to do this in one big bite on Day One. PJM has had about 160-odd incremental changes over the years. Get the important parts right and then build in the others as you grow in your comfort level, your infrastructure and your knowledge. There are some good things to come if you work through the process with all the right constituents.

Comment: I represent wholesale loads that are load-serving entities owned by their members. We do believe there has been discrimination against wholesale load in the guise of service to retail customers. We don't know what goes on behind that curtain – it's not on the tariff. Personally, I support putting all loads on the tariff and having a consistent set of rules. That does not mean that I support all of SMD and retail access. You have to look at them individually. How do we manage a regional grid for the benefit of all the loads that are served in the region? What disturbs me about the jurisdictional discussion is that retail has to come before wholesale, or wholesale after retail. But we are all trying to serve customers. I think it is a turf battle.

Comment: Guaranteed continued access to the transmission that you have contracted for, or that you've paid for is very critical. I don't see how a four-year transition period with CRRs and suddenly going to an auction does that.

Comment: That is a key concern for regulators with coops that want to maintain access to their low-cost generation, as well as IOU customers.

Comment: We hear the same arguments about how we aren't able to protect native load and continue access to company-owned generation. I think FERC effectively rebutted that argument both in SMD and in stating its intentions. What don't you believe about what FERC is saying? SMD and the RTO West proposal lead us in the direction of solving some of our problems, such as knowing where the congestion really is, locating generation appropriately, and dispatching more efficiently. I hear about an alternate proposal to SMD, but I have not seen it.

Response: The assertion without evidence is that inherently the vertically integrated utility unduly discriminates. I don't think there is a single citation to a circumstance in the West to which FERC's SMD NOPR cites that kind of concern. If there is an issue of over-reservation of transmission for the purposes of controlling the market, investigate and decide what to do about it.

Comment: Because the pricing is so confusing, there is no way to really know what is going on. You could allege discrimination and be absolutely correct, while being unable to demonstrate it clearly. Or the contrary could be true.

Response: Many of us suffer from a disconnect between what the literal reading of the SMD NOPR suggests, versus what we've heard evolving over the last few months in terms of FERC's intent. In fact, I am thrilled that FERC didn't intend to say a lot of things that I think it said. I am not being harsh or critical. In fairness, FERC needs to be more specific in a future NOPR, or in the context of the RTO proceedings. I love that fact that we are not supposed to see any impact on generation prices, and yet the CRR scheme does not guarantee continued access to the low-cost generation. It will be good to say that specifically in a final rule; this is an evolutionary process, and we'll have to get there.

Comment: It took three meetings with FERC staff before I understood CRRs and that native load would be protected.

Question: An issue in the south is the cost-benefit analysis. I suppose that reasonable people agree that the results of a new study by Charles River Associates are incorrect that it is a close call for the southeast as a whole, but for Florida, for example, the results indicate that on balance, the cost of implementing SMD would exceed the benefits. In such analyses, there are almost always winners and losers and the test is if the gains to the winners exceed the losses to the losers. If so, it passes the net social test, and you move ahead. What is FERC's legal obligation in viewing these cost-benefit studies? Does it look at the nation as a whole, or the regions as a whole because all of the markets are interconnected?

Response: Nothing in FERC's SMD NOPR precludes a state from continuing its cost-based regulatory system. The markets are optional. Cost-benefit studies give a broad snapshot; your inputs can totally control your outputs. You look at such studies for what they are – a tool. They do not look effectively at efficiency or the lack of it in the dispatch, which is an issue in the southeast. FERC's legal obligation is less important to me than its moral obligation – to look out for the customer. That will guide the outcome of SMD and the implementation of RTOs. Size matters: there are some benefits lost and costs added when you have small organizations. I believe there are some benefits to Florida that could be addressed through effective market design, a larger RTO, the elimination of some barriers and more competitive solutions to both generation and transmission. Florida may not agree. There should be better accountability at FERC for the costs of the existing ISOs and the development of RTOs. We have an obligation to make sure FERC maximizes the system to deliver to customers the changes that add value. No single cost-benefit study will answer those questions.

Question: My understanding is that FERC is leaving these things to the states, although recognizing that they are important to take care of. Could you clarify this? I also caution that not all demand response programs are environmentally friendly. Anecdotal evidence says that there are a lot of diesel backup emergency generators that have been adjusting their testing schedules to take advantage of peak pricing programs that have been offered through demand response programs. Some are permitted for 5-6 times what they need for testing and maintenance and some operate near population centers and at peak hours when air quality is worst. Will further iterations of SMD address this?

Response: FERC has been less than innovative in its approach to demand-side management, and has encouraged programs that probably damage the environment: in some cases, those are the only programs available. It has never dealt with the pricing issue. The reason you see what is largely a placeholder for demand side in the NOPR is that 100 percent of the participants said there was a place for it in the wholesale market, along with the other options for solving problems. I do not think we can afford to continue to do demand response as a piecemeal project. Implementation and retail programs should continue and expand. I'd give everyone a real-time meter to see if we can get a rate design that makes it worthwhile.

Comment: In our experience, we are not getting anything from the generation side to help support demand response, so it becomes more of a challenge. That is one of the downsides of restructuring. Commissions can order it, but somebody has to pay for it and it will not be the utilities. There is no question that there is a need for demand response.

Response: Many states have figured out how to keep doing the programs that provide benefits for customers. Over half the states have some benefit charges that are non-bypassable but do not cause a competitive disadvantage that fund those programs.

Response: As I read FERC's SMD NOPR, the ITP has a direct responsibility to at least address the question of demand side management. While I do not criticize that, you have to understand that in the vertically integrated states, the end-use customer only has the right to make a call against the utility for delivery with its obligation to serve. The utility has to deal with the issue of pushing product back into the grid if you are going to have a demand side program. It may be different in the restructured states, but it shows the differences between them and the monopoly states. And the typical residential consumer will not tolerate exposure to the wholesale market.

Question: Shouldn't they have a choice? I am not advocating for or against demand response, or for meters in the home. My point is that there are some unintended environmental consequences to the operation of some of these programs.

Comment: California has installed real-time meters in all loads over 200 kW. Its public utilities commission is working on the tariff. Since real-time means different things to people, there are four real-time proposals, none of which is real-time. Some studies have shown that some interested homeowners have reduced their peak demand by up to 50 percent. The California Energy Commission supports opportunities for metering in the home, but not mandating it.

Comment: There is a big difference between time abuse tariffs and real-time pricing. In the abuse tariffs, the monopoly provider at least continues to take the risk. In a real-time price, all of the risk shifts to the end-users, with different consequences in restructured and monopoly states. If the risk shifts to the end-user, the utility's rate of return ought to drop because its risks are now lowered. The typical utility does not want to talk about that.

Comment: I think the NOPR says that it wants to remove discrimination for native load and have a single tariff for all. At the same time, it wants to protect the native load so that it can purchase generation and have CRRs. If you can protect the native load for the financial implications, you can preserve the benefits. Another benefit for native load is that you can actually prevent other people from gaining access to cheap generation that you do not own. You can take advantage of that access to that cheap generation for your benefit – buy it when needed, not when you don't. Because it is not physical, you cannot protect the other components of the transmission grid that are used to gain access to generation that you do not own. It is true that native load loses a benefit it had in the past – precluding others from coming in and using the grid. FERC's SMD NOPR says that there is a mechanism if you want to protect your native load to gain access to your generation for your transmission. But if you want to use native load to prevent others from gaining access to transmission and generation that you don't own, NOPR will not allow this discriminatory part. It will not recreate the discrimination because of the distinction between physical and financial rights.

Question: People criticize SMD for "one size fits all." The same details are applied in all regions and maybe all regions are being asked to move forward in terms of restructuring wholesale markets. Some of the discussion about FERC's flexibility in the RTO cases is an attempt to fix the first criticism. Can you let some geographic regions, which actually aren't electric regions, behave differently in different parts? Could we phase in SMD by letting people opt in, opt out, or will this be a problem?

Response: The consequences will be that a region that attempts to isolate itself economically ultimately will incur a significant deficit, particularly in economic development. I don't see how the southeast or the west can stay out on its own.

Comment: Three RTO mechanisms are evolving in the west. There is also intensive discussion about the seams issues. Initially, FERC wanted a single, west-wide system, but that posed almost insurmountable issues. Will we be better off with three RTOs? Come back in 10 years.

Comment: SMD provides principles that many have identified as critical to making markets work. RTOs are the way to address regional problems in a disciplined way. We cannot lose sight of the fact that the grid is integrated and that the southeast, for example, is not an island. To varying degrees we are all suffering the economic consequences for not making the critical decisions to build the platform for the next generation of energy markets. While we can argue about discrimination forever, we have an imperfect system that is not getting the needed investment, yet we have markets that are regional. It will be a disaster if we evolve with dramatically different sets of rules, or have groups that evolve or not. Are we a national grid in the next few years? Perhaps one works to that. But we are regional grids. Today's political answer is not tomorrow's economic answer.

Question: The reluctance to replace the existing system with something else is basically about maintaining discrimination and pancake rates. At the same time, new generation will come from merchant plants and be delivered over a series of lines, every part of which are owned by somebody who has the ability to protect their own generation. How do you get the most value if you maintain pancake rates and you continue to allow discrimination?

Response: That is where the ITP and CRRs kick in.

Comment: A merchant generator who is a spec builder, has no obligation to serve anybody, whereas a utility is a corporation that is in the public interest.

Question: Do you have the ability to discriminate when a utility buys power to serve its load; incurs costs that are passed on to the customer; and tries to ensure that the greatest benefits from the merchant competitive market will be passed on, each time the utility runs across a transmission path owned by someone else who owns generation serving another load?

Response: For the foreseeable future, there will be no independent power producer spec construction because Wall Street has made its judgment. The IPP, at least in the west, will build if it has a long-term contract with a vertically integrated utility, because it can then borrow money. If it has that long-term contract, it will have transmission access, or if it's the spec producer, it can buy into the transmission system for access.

Question: Does FERC contemplate having the same transmission rate for wholesale and for bundled retail? If transmission costs increase because of SMD or the increased ROE, will they be offset in the retail mechanism?

Response: Transmission pricing and cost allocation are still under debate. We need to deal objectively about the cost allocation for both existing and future transmission, and make sure those costs are allocated appropriately. How the retail rates are set is up to the state public utility commissions. Transmission cost is a very small portion of the bill, but a small portion that has the ability to affect generation – a much larger portion. If it is done in the right place, a significant increase in transmission investment has ripple effects – keeping you whole as a retail ratepayer and reducing your cost because the cost of generation overall is reduced. Get those economic signals right and you will be allocating resources more effectively.

Comment: The native load debate has always been about whether or not it is appropriate, efficient and fair for a utility on behalf of its native load to access the grid to bring in non-firm power on an opportunity basis in circumstances where it may keep another willing customer off the line. I think it is unfair to say that native load customers are not harmed when that is taken away. It is also fair to say that the market is harmed when it is not taken away. We have to be careful about what we define as undue discrimination. Some systems were specifically designed to displace their water with non-firm imports -- Idaho Power is a perfect example. If it does not have that ability, it is at a significant disadvantage for its native load customers. It's not a matter of discrimination or unfairness, and I think this is one reason why there is some discomfort in about SMD.