

**Special Session on the State of the Wholesale
Market: Reliability and Regional Trade
Harvard Electricity Policy Group
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RAPPORTEUR'S SUMMARY*

Morning Session: The Wholesale Market in Practice

Some market participants have asserted that the wholesale market in the summer of '99 was less robust than in recent years; good deals were left undone. Is the market less robust than it has been or should be? If so, why? Some point to transmission constraints and reliability concerns as the major problem. How did the various pricing, transmission loading relief, and reliability mechanisms function and how did they affect the market? Others maintain that if the market is shrinking, it is simply the result of a diminution of the excess capacity. And there are those who suggest that the market is not ailing at all—that all markets ebb and flow. What does recent experience suggest? How permeable are the seams between regions, and at what cost?

Speaker One

The New England ISO is tightly interconnected with New York and has DC ties with Quebec and a radial tie to New Brunswick, and just the ocean on the east. The wholesale market started in May. The ISO was formed organizationally in 1997. There are about 245 employees, 130 participants, 330 generating plants, and installed capacity of 25,500 megawatts. The

peak this summer occurred on July 6, with 22,523 megawatts, so it was tight. The market started with an early heat wave on June 7 and 8, so five weeks into the markets there was a tremendous challenge.

There are substantial coordinating procedures in place among the regions within the Northeast Power Coordinating Council (NPCC). Those worked very well in terms of getting

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through these tight days. There were some delays and confusion in terms of how to buy emergency power and move it around. So those are some things to focus on going forward.

During the rest of the summer, there were 22 days in the two critical areas that NEPOOL monitors of 90 degrees or more compared to five last summer and 10 on average. There were 15 days of peak loads of 20,000 megawatts or more. There were even peak loads on Saturday of 20,000 megawatts. There were 11 incidents of operating procedure number four, which is invoked when there are capacity deficiencies, compared to five for the summer before that. So it was a very stressful summer due to the heat.

The NEPOOL market system is a single settlement system. There are no forward settlements as designed in the New York market. Congestion costs are socialized. There are seven market products--energy, installed capacity, operable capacity, ten-minute spinning reserve, ten-minute non-spinning reserve, 30-minute operating reserve, and automatic generation control. That's a lot of markets. One of the issues is what is really the difference between a reserve market and an operating capacity market. Are they basically the same thing?

There is good news, and some problems. The good news is, as the NPCC report discusses, the emergency procedures worked very well. NEPOOL continues to coordinate closely with neighbors in New York, Quebec, New Brunswick and even as far as PJM in Michigan on regular

conference calls when system conditions get tight. And the lights stayed on. And generally, the energy market worked as designed for unstressed conditions. Overall, the new markets survived in spite of the stress.

Nevertheless, there are a number of problems. One is that the market signals were not adequate in all cases or as often as they should be to provide incentives to the generators and the loads to do the right thing for reliability. In order to have a well-working competitive market, the price signals have to be such that people respond to the price and do the right thing for reliability. Some after-the-fact price revisions had to be made and some price caps implemented.

Pricing incentives, particularly in ancillary service markets, seemed to be more of a problem this summer than the energy markets. The way the markets are designed is that anything you can't account for through the market gets paid for through uplift, and uplift is socialized. There are agreements as to what portion of that the loads pay and what portion the generators pay. To the extent that you don't have a market capturing all the costs, there is leftover that goes into uplift. And people complain because it is too high. So we need to come up with market designs and incentives that will minimize that uplift.

The operating and reserve markets needed to be capped. When there were deficiencies, there was no more cap available but there was no response from the load as price went up. So the ceiling on operating capacity was the

sky. We took some initiative to cap that.

Another issue was posturing of limited energy generating facilities. There are two pump storage units in New England, one a fairly large one that runs more or less on a weekly cycle and the other smaller and tending to run on a daily cycle. The owner of the one that runs on a daily cycle wants to put its bids into unit commitment and get a schedule from the ISO, but if the clearing price at any point during the day is high enough, he wants to run and have his bid dispatched. But when we do unit commitment for the next day, we may be counting on that pump storage plant to be available over the peak. If he is chasing the bid price early in the day, he can run out of water before we get to the peak. If we are not in a tight capacity situation, that's not necessarily a reliability concern, but many days this summer it was. So we had to posture the plant, force it to not run early in the day and save that water for the peak. This gets into the conflict of whether we are affecting the owner's rights to be dispatched to the market price.

As for excess generation off-peak, we had price signals that were not encouraging units to shut off at night, and we were overgenerating. We had to force these units off. New England has a manual process to implement economic dispatch. The burden is on the system operator to make sure the plant is following the base points, and if he isn't, the plant gets paid for whatever he's doing. So I am pushing to work towards an automatic electronic base point system.

The unit setting clearing price is a problem. You may want a unit to move to a certain point 30 minutes or an hour from now. Which one sets the clearing price?

The ISO is involved with purchasing emergency power. In a well-designed market, as we get better at this, supply and demand should dictate emergency power purchases.

There is a disconnect between transmission maintenance and congestion costs. When you socialize the congestion cost and the transmission companies are divested of generation, their goal is to do their maintenance when it is cheapest for them or when weather conditions are optimal. That may end up being the time when you have to run units out of merit in order to support that outage. Where is the incentive for transmission owners to do their work at a time when it has the least impact on the system? This is particularly coming to a head with the interconnection of new independent power producers. Lack of demand price elasticity--again, the market will never work correctly until loads are responding to price signals.

There are two types of uplifts in the New England markets. One is for reliability, when you run units out of merit in order to secure the system for transmission constraints. That is socialized, and creates disincentives. The second is energy uplift. There are two types--payments for units dispatched in advance of a five-minute dispatch for load pickup and dropoff, and payments to generators when the

operator fails to recognize non-performance per dispatch order. The incentive is in the wrong place; it has to be on the generator.

New England is working on three primary areas: A multi-settlement system, which I believe will address a number of problems, particularly the pump storage problems; congestion management; and electronic dispatch with an automatic algorithm defining the clearing price.

Speaker Two

I view myself as a shipper. The view that we bring to the transmission business is that a robust energy market is good for business. If the market is correct, we will have added more value and extracted more profit.

On tariff reform, it goes without saying that we have to find a way to get rid of what is an accident of history, the pancaking regimen that we have in most of the country where ISOs are not yet operating. We have to find a way to get regional application of tariffs, find a mechanism to value the constrained interfaces and use that input to help to constrain the marketplace. At the same time, we have to find a mechanism, particularly a long-term mechanism, to send signals to generation. As for ex-ante pricing, the marketplace doesn't work if the winners and losers are determined after the market closes. We have to get past the grandfathering of contracts. If tariffs are to work, we have to move to a market in which the needs of the current marketplace govern.

On the subject of transmission capacity upgrades, economic signals should give you some indication of when to build. If you can figure out a way to predict constraint management costs into the future, that will tell you when you ought to build transmission. That is, you don't want so much transmission that you never have constraints; that is unaffordable, and you won't get licensed. We have to figure out a mechanism by which those who run the system well from a reliability standpoint, those who reduce the amount of constraints as opposed to increasing it, are given incentives along those lines.

In our area, Minnesota and Wisconsin, those two states, as much as they may try, do not cooperate as well as they could in the construction of new facilities. A project that has been envisioned for about nine years now may be turned down in one of those states after having been approved in the other. There needs to be regional cooperation--as opposed to federal pre-emption, which will not work on Main Street.

We are having increasing difficulty building transmission, not just interstate but intrastate transmission. The public perception of its aesthetics is not improving. We need to find a mechanism to foster cooperation among the states so the transmission facilities that are built are those that are needed, and are needed for the region, not just for local parochial interests. Unless the transmission investment reduces total societal cost, it's not a prudent investment.

On price discovery: My sense is that there needs to be an exchange if you are going to create market confidence that the system isn't being gamed. There has to be a mechanism for getting real time pricing for customers. There are not many applications of electricity that justify \$7,000 a megawatt hour. It's a different question if I have a heart lung machine operating, or a microchip manufacturing facility whose electric costs are a small fraction of their total cost. We have to find a mechanism to get that signal out there.

One of the reasons for having a market and price discovery is to get an ancillary services market price, so that we can buy ancillary services from willing sellers instead of coerced market participants. If we can buy them on the open market, we're more likely to get a product that's of value and we're more likely in the long run to sustain that product's availability.

Participation in the exchange must be voluntary. One of the reasons for that is risk profile. Various market participants have various risk profiles. Some need desperately to have price predictability as opposed to minimum price.

From a provider's perspective, we have to have operating reserves. It is the only mechanism by which we can adjust to change conditions on the system. I am not sure whether planning reserves, on the other hand, have a long-term role in the market. I have not seen that requirement producing any improvement in

reliability. Without reserves, markets will fail.

Let me wrap up with a probabilistic risk assessment. First, if there is not confidence in the market, then the market is not reliable. Perception is reality; we have to communicate the true reality of system reliability. The contingency analysis that we are using today is inadequate. I don't think it either fully captures the risk nor allows the utilization of the system to its maximum ability when we arbitrarily impose a contingency analysis when the probability of that contingency is virtually nil--and then fail to impose a double contingency analysis when that double contingency is a lot more likely than a single contingency might have been in a different circumstance.

Market use affects reliability. The stability event that occurred in the Midwest in June, 1998 took place because the market was using the system in a way it had never been used before. And environmental circumstances were present for which the probability was low. When we took the probability of the transmission loading being high from five or 10 percent in the mid- to early 1990s, to 80 or 90 percent today, the probability of a double contingency event coming and causing a stability event went up dramatically. It isn't obvious unless you do some kind of a probabilistic risk assessment.

Consequences versus probabilities is another thing we have to look at. Shedding load in order to avoid the prospect of shedding load doesn't sound like a very smart decision,

particularly if the subsequent shedding of load has a small probability and you shed load as a one in one probability to avoid it. On the other hand, if you have to shed load in order to avoid a stability event that takes the whole Upper Midwest out, that is a prudent decision.

We do some of this today, almost exclusively intuitively. But we need more sophisticated statistical tools to give this more credibility and make it more reliable. Probabilistic risk assessment can create the opportunity for us as a transmission provider to produce substantially increased value to customers, improved reliability and increased throughput.

Question: In your probabilistic approach, would you include the concept of price-sensitive ancillary services?

Response: There is no doubt. As I've talked about probabilistic risk assessment, it has not had an economic factor. But if the incremental improvement in safety, in reliability, is marginal or if you can get that same improvement and reliability by some other mechanism, such as reconfiguration of the system, that ought to be an opportunity in the marketplace. The marketplace is better off for it.

Question: Would you allow at-market pricing?

Response: Absolutely, if the purchaser can stand the risk. If you can't take the risk, then you ought to have a way to avoid it. Predictive pricing is a way to

do that.

Speaker Three

I am going to make some comments on how we in the Midwest experience and perceive the market. The utility that I work for serves 30 cities who own the utility. We're about a 700 megawatt load. Our industrial load is very high. We operate in four different control areas, four different transmission systems, two reliability councils. We own generation remote from our load. So we have a fairly complex supply, about 50 percent in assets and 50 percent in contracts. We purchase a substantial portion of our energy on the market. Most of our contracts are dispatchable in the sense that we can take the energy or buy. One of our objectives is to get everything on one transmission system, one reliability council, one set of rules that will make life much easier.

The Midwest market is not a model for anybody. It's a highly opaque market, completely bilateral and in some senses dysfunctional. Some entities in the market, primarily control areas which are also transmission owners, have significant advantages over other participants, including the marketers and the transmission dependent utilities.

Did the market work this summer? The lights stayed on. They've stayed on the last several summers, despite significant shortages at times. And the utilities worked it better this last summer than the previous summer in coordinating between the reliability regions. So in that sense the market

worked, but maybe only in that sense.

We are in a very constrained area. Our load at peak conditions is about 10,000 megawatts in the eastern part of the state. Current import capability has gone down substantially with the closing of a nearby nuclear plant, dramatically affecting our state's reliability and lessening our import capability substantially. It is almost impossible for us to be able to predict what transmission import capability is going to be next summer or the summer after that. It's one of the most changeable numbers I've ever run into.

There are four transmission systems in this part of the state owned by four different utilities under four different tariffs. And at times over the last couple of years there has been, because of the available transmission capacity (ATC) and capacity benefit margin (CBM) calculations, no ability to move power within this system from one utility to another because, we're told, there is no ATC. This system was planned and built as a single system under PSC regulations, so it is planned without reference to ownership, supposedly as an integrated system. And yet there was a time this spring when one utility was restricted and could not buy from any of the other utilities in the area because a line was under repair.

There is enormous frustration in attempts to build transmission. A neighboring utility has a line planned that crosses a river that goes through two states. The state that needs the line for support for load has approved construction of the line while the other

has not. That state may not approve it because it is difficult to demonstrate benefit for its ratepayers. That creates significant reliability problems.

We have another proposed line that several utilities have filed for. There are already three web sites opposed to the line. Attorneys have been hired. There was a demonstration at the PSC and at the state capitol against the line. The controversy is significant, and the chances of getting the line built are no better than 50-50.

So what we see is an increasingly constrained market. We expect the shortages to continue for a significant period of time. What that has led to is extreme price volatility during the summer. When we went through that in 1998, some believed that it was a one-time occurrence. But at this point, it looks like an annual occurrence. Data published by *Megawatt Daily* gives an indication of what we are dealing with: Very low prices for a substantial amount of the summer, then significant price swings. The price spikes in our area were worse this last year than the year before. Because of all the uncertainty, utilities are holding their capacity off the market.

In terms of reliability, there are no real teeth in our market. We have a stakeholder process that results in compromises. There is very ineffective enforcement of rules. A lot of utilities feel that certain players are not maintaining their reserves in accordance with the reliability criteria and are leaning on the system, but there isn't much of a way to deal with

that. There is poor information, and significant information disparities between players. Redispatch has not worked. There is no standardization of ATC or CBM.

In terms of gaming in the system, control areas can declare emergencies, in which case they can ignore ATC limitations. We believe that that happened this summer. Also this summer, some utilities leaned on the system significantly when out of balance and took a substantial amount of power inadvertently at very high price periods. There is an incentive for many utilities to create control areas because of these commercial advantages. The bottom line is that until all transactions and uses are treated the same, there are going to be these continuing disparities in the market which make it very difficult to operate.

As an example of the kind of gaming that can go on in the system, we have C, a control area, and its load, then two adjacent control areas. An IPP or some plant that C does not own is located in its control area. It sells its capacity to A as a network resource, but sells non-firm energy to C. The sale of the non-firm energy to C is not tagged because it is in the control area. So when line loading relief is called, this sale of non-firm energy to C can continue while all other sales of non-firm energy in the region are cut. That is because it is within the control area. Only the control area utility can take advantage of this. If I buy it from the IPP, my purchase will be tagged and I will be cut. With more merchant plants, this advantage will be exploited

until all transactions are treated identically.

Or there is a situation where D is unable to sell to C in a line loading relief situation due to NERC transmission loading relief (TLR) or ATC, but he can sell to B and B can sell it into C. Electrically, the transaction is identical to a sale from D to C.

The difficulty with a stakeholder process is that you can't cure those problems. Another party may not be willing to object to what I'm doing if he sees it because he has other transactions out there. So the process never gets sorted out.

The solutions are obvious. You need a strong transmission system run by one regional entity that has no interest in the generation market. You need to have the control area function neutrally, take the commercial advantages away from being a control area so that it is strictly a reliability issue. You need to unbundle service so that everybody takes transmission under the same terms, rules and conditions. You need a power exchange, a transparent spot market. But how to get there is apparently a lot more difficult in our region of the country.

Speaker Four

We have had a substantial growth in TLR events since 1997. We're looking at close to 700 TLR events, and if on the average one overload is 100 megawatts, and it takes about 10 megawatts of relief or curtailment of

transactions to buy one megawatt of relief on an element, we're talking about 70,000 megawatts of transactions that have been curtailed since the inception. If you look at different regions of the Midwest, if TLR events occur in any one of those regions, it impacts the others. That is really balkanizing the Midwest.

After the late July price spike in the Midwest, at a security coordinator congestion management work group meeting, it came out in discussion that on two occasions 4300 megawatts of transaction in the previous couple of weeks had to be cut to knock off a 400 megawatt constraint. Local control actions may have been used in place of the TLR cuts, but no mechanism currently exists to compensate parties for local control. Just yesterday in one of the trade publications was discussed a case where there was 1100 megawatts of cuts that looked like they were mistakes. Obviously, market confidence is still not very good right now.

The next thing I want to touch on is the concept of the CBM-TLR link. On July 29, PJM was importing approximately 3000 megawatts from New York, and a good chunk of that was being imported on nonfirm transmission. The reason why a lot of that was being imported this way is that they had a CBM set-aside so that in case they got into a generation deficit they could reach out to generation on the other side of the constraint, which they didn't have contracts with, and be able to bring that in. But because they had that set-aside, less firm transmission was being

made available to the marketplace, so it was subject to TLR cuts. This seems to undermine the whole intent.

Is it a contract problem? Some would say yes. Is it a TLR problem? I think it definitely is. But you put the two together, and it leads to disaster.

The market impacts are decreased liquidity and increased market balkanization, which leads to increased market volatility. I think the last two summers support that. It also reduces reliability and market confidence. Because of the TLR problems on any given day, if I can't buy firm transmission, I will go elsewhere, because I'm not going to subject myself to that risk. And how many other market participants are doing that? That reduces liquidity.

The foundation to a solution is comparable service. If we put everybody under the same tariff, then everyone suffers the same ills, and everyone has equal motivation to solve the problems and to work together rather than in opposite directions.

Discussion

Question: What is the process for correcting these problems? Some areas have stakeholder boards; others are more amorphous as to exactly how these things are handled. Are the problems going to solve themselves? Do the regulators have to assert more authority?

First Response: Taking the word "mandatory" out of the FERC NOPR (Notice of Proposed Rulemaking on

Regional Transmission Organizations) is a significant problem. In the Midwest, the states are not able to solve these problems as some others have, and if you rely on a completely voluntary process, there are tremendous competitive advantages that people are loathe to give up, and you have to get the cooperation of the major transmission owners and others, which means significant compromise.

Second Response: There are a few different components to an answer. First is the security assessment process, the determination of when you need TLR, and conversely, how you calculate ATC. I think that must be done by an independent party. My experience is that a constituency- or stakeholder-based organization cannot do it effectively. Second, it's the tariff, stupid. You've got to get the tariff right, and it has to cover a large region. Third, you have to find a mechanism to allow entrepreneurial spirit to expand the marketplace. We are never going to be able to build enough transmission to clear constraints. We have to do it through markets. We have to do it through creative technological applications of either risk assessment or through hardware. We have to introduce entrepreneurial spirit in order to allow creative parties to find ways to build where construction couldn't otherwise happen, or to utilize facilities more aggressively than would otherwise happen.

Third Response: We are seeing things in the marketplace that I think will begin to cure problems. The NERC reliability legislation is very important.

We need more transparency. We need to continue to have new pricing innovations. Alternative dispute resolution is an important component to solving disputes outside of litigation, outside of FERC, outside of courts. And we are continuing to perfect market rules.

Comment: Voluntary versus mandatory makes a huge difference. If FERC had clear authority on the RTO issue, there would be no debate over whether the control area function should be neutral, whether the security coordinator function should be neutral, and whether everybody should be under the same tariff. That would be clear. But as long as it is voluntary, we have compromises that result in sub-optimal solutions.

Question: There has been a lot of talk about the multiple control areas and the need for more efficient congestion management. Yet there doesn't seem to be a common outline emerging that would go toward fewer, larger control areas with transparent markets. Would that sort of framework help us meet our goals?

First Response: In the Northeast, the three ISOs, PJM, New York and New England, signed a memorandum of understanding to work together to make the markets more transparent, eliminate the problems with interfaces, look at ways to standardize closing times, and perhaps standardize the way bids come in and how transactions are coordinated. Currently, the three ISOs are similar in many ways, but also very different. A question that came up is whether there should be just one big

ISO in the Northeast. I think we have to be patient, and once those three markets become stable, look at ways to make them work better together. I think we have a framework that will go a long way towards those objectives.

Second Response: You have to be careful in using the term 'control area.' Load balance area and transmission control area are different things. And one of the things to keep in mind is that there is no such thing as a contract path except as a legal and financial fiction. If we think instead in terms of generation to system and system to sinks, that may help us solve the problem.

Third Response: As a generator developer and owner, under the current paradigm, when I plug into a control area, I have to deal with generation imbalance, and I am locked into buying it from the traditional control area. I would like to be able to link my generators, which are relatively close together. I should be able to do that and it shouldn't be that difficult to do. The control area will be significantly smaller, and we can solve some of these problems.

Question: I am interested in the issue of siting the line across a river that goes between two states. One of those states is one of the few where the siting statute specifically says that you have to take into consideration the impact on other states. So I'm interested in how that issue is playing out.

First Response: The permit has been granted in one state. The other has not decided, but there is tremendous political pressure to not approve the project because of the esthetics. The river is a natural and scenic waterway, and the area is a prime ex-urban development area, so there is also opposition from people who own luxury homes in the area and want to maintain the pristine nature of the area. There is also a perception that the other state has neglected its electrical infrastructure, and now needs help.

Second Response: Our new state statute that was passed recently adds language that makes regional need the justification for construction. And it directs the governor to attempt to negotiate in inter-state siting with the adjacent states. I don't know whether this will come together, but there is an attempt in the law to address these issues. On the curtailment issue, the bottom line should be that firm load is not cut no matter whose it is. The difficulty is the enforcement mechanisms. We have TLR that deals with 10 percent of the transactions. FERC says we have to take comparable actions and re-dispatch our system, which is a tariff obligation. There is no recordkeeping of what goes on when a transmission provider in a TLR event has to do something in its own system presumably to treat itself comparably. It is a poor system.

Comment: There is a big financial risk for any entity that is caught between a market that has such volatile prices, and an obligation to serve on the other side. So complying with voluntary rules can have drastic impacts on the

finances of a company. Looking at next summer, we are going to have serious problems if we don't fix the system.

Response: If you look at the load growth that we are seeing, and the turbines that are being put on the ground, we are not keeping up with the growth.

Question: What does maximizing throughput mean? Shouldn't we be focusing on who is better to manage congestion rather than say it is only if you are in an independent transmission company that you get to solve this problem?

Response: The RTO acts as a traffic cop, trying to make sure that I don't try to oversell my system. On the flip side, if I have economic incentives, I am going to do what I can to solve the constraint problems. But congestion management is a huge part of this equation.

Question: Colleagues have been telling me for a while that the economic advantages of being a control area operator are inhibiting the movement toward RTOs and exacerbating many of the problems that have been described this morning. Would one step towards a solution be to require control area operators to do all the things that are being required of RTOs, or find some other way to remove the special privileges of being a control area operator?

First Response: If we get the legislation that reorganizes NERC, all of the regional councils become

subordinate to NERC. NERC would be an umbrella for the regional councils.

Second Response: There are two models: PJM, which is an ISO or an RTO that is the control area, and the Midwest ISO, where the owners fought for control area responsibility remaining with the existing transmission owners, and the ISO would not be a control area. These are competitive concerns as opposed to reliability concerns, which the legislation stays out of. So this issue will keep coming back.

Question: Are there lessons that we can learn from market operations that could lead us to designing better markets that would respond to the questions that have been raised, especially around congestion, TLR and the failure of the market re-dispatch proposal from NERC? Do we need to stay in a physical transmission market?

First Response: The New York design is primarily a financial model. It doesn't maximize throughput *per se*, but allows transactions to financially move if the individual that wants to move them is willing to pay the price. We're never going to be able to decouple from the physical delivery.

Second Response: If you look at this source-to-system and system-to-sink model, it looks a lot like a financial model. Maybe that is the paradigm.

Afternoon Session: Reliability and Regional Trade in Theory

The experience with the practice of wholesale markets points to the need for improved methods of managing the seams to preserve reliability and support a competitive wholesale market. This topic includes coordinated congestion relief among existing system operators, transmission loading relief protocols, and the rules for arranging power trades over long distances. The design of reliability institutions has important implications for the operation of the market. The design of market institutions has important implications for reliability. Advancing the discussion

requires a review of the state of the argument and examination of alternative proposals that build the means for the market to reinforce reliability.

Speaker One

Transmission ought to be able to be run as a business. What are the competitive market issues that need to be taken care of by any kind of a transmission business? It is very difficult to conceive of a market that does not have a whole host of willing buyers and sellers. That host of willing buyers and sellers leads to a lot of trading, and that's how you get liquidity. Trading at hubs is an essential part of getting that kind of liquidity, since it gives you the opportunity to invite more willing buyers and sellers to come to a common point to trade.

Essential to all of this is a rationalized transmission service business because if, ultimately, the product that you're trading cannot be physically delivered, there is a disconnect between the physical and financial aspects of the business. And any business where that disconnect occurs is likely to suffer hesitation on the part of those who ultimately will take their business to physical delivery. It is essential that we have not only supply elasticity but also demand elasticity, and it has to be

more than in the form of interruptible contracts. We have to figure out a way to get price signals to consumers to get them to not consume when the price is too high. A lot of people think that that means you have to get the price signal down to every homeowner and meter in the industry. I think you can

get a large measure of the discipline you need by simply sending that price to the largest customers.

An essential ingredient is informed consumers. If we can lead ourselves to a competitive marketplace, we'll unleash an incredible amount of technology, creativity and innovation in the electric power delivery business. Furthermore, to the extent that industries around the country use electricity and have some price sense about it, it's going to unleash creativity in regard to how they manufacture things and move the products that they buy and sell. A remaining challenge is that this commodity doesn't have a good storage medium.

What is transmission as a business like today? It is considered a monopoly business. But because it comes from vertically integrated utility origins, it is functionally distracted by the fact that one arm of their company is supplying customers and another is in the merchant trading business. This leads others who aren't transmission owners to wonder whether they're getting the same fair treatment in the delivery business that the transmission provider is getting.

I would also describe this as a very fragmented enterprise, operationally and commercially. We have something like 3300 transmission owners in the North American grid and about 140 control areas in the grid, four interconnections. The UK has one control area—a grid that was

originally owned by one party, the government. So there is a level of simplicity that they were able to take advantage of. It has been a cost-based regulated enterprise, and the service products that we see today are results of that regulation-based era. When was the last time a transmission customer was asked whether one of these products served their needs?

I suggest that transmission is a future business. But for this to be a future business, a good business, it has to be functionally distinct. Those who are providing the transmission service have got to have as their business motive to move power, to be nothing but the shipper. You have to be looking at things like independent transmission companies. Transmission has to be a more cohesive enterprise, so that even if there are multiple owners, customers don't have to worry about what city to go to to arrange the next piece of transmission.

This enterprise is likely to remain regulated, but we have to re-invent regulation. We have to do performance-based regulation, not in the sense of how well did you reduce your costs, but looking at how business behaves in competition and what kind of performance measures will give incentives to transmission providers to operate as a competitive business. It demands that we look at analogies to how other businesses operate, like shipping businesses. They have to deal with the laws of physics as well. But they have internalized those technologies into the scope of their business.

We need to have customer-based service products, which means you go to a customer and ask, What do you need? We need to think, What does the next person in the chain of this industry need from me? And it ultimately needs to be an internalized risk management business. What are the risks of shipping power over the transmission grid? As long as you externalize risk management, you're going to have trouble figuring out how to get incentives in the right place, and you're going to get game playing.

One of the ways I look at transmission is to think about it in layers: the physical layer, the hardware, and the maintenance and operational issues that go into keeping that hardware viable. The top layer is the one where the picture is somewhat incomplete. What do we want transmission to be when it grows up? Today we have OASIS sites that describe what's available, transmission products that are billed on the regulatory era of old--and that's about it.

Is there is long-term solution to the transmission service product business? I don't know. Ultimately, I'd like to see all of these things done by a transmission business. But in the meantime, in order to get there, we have to make sure that they are consistent, starting with product design, to whatever kind of reservation service you have, all the way through congestion management and ultimately settlement. And as long as we have multiple transmission providers in the same interconnection, we're going to have to be sure that these things work

spatially. That is, whatever you use in PJM has to be compatible with what you use in New York, has to be compatible with everybody else.

Speaker Two

I would like to outline a couple of things that are different in the California model than in the models in the East. First, California went to full retail access at the same time as the ISO began operation, which is different than in many places. California combined three control areas into a fairly large control area, which has resulted in clear improvements in efficiency and in generation patterns and dispatch. That speaks of the need to have fairly large RTOs and to combine control areas, as opposed to simply applying rules to a number of smaller control areas.

The ISO facilitates the energy markets, but the energy market is handled separately. All energy market transactions, whether they're bilateral or through one of the exchanges, are handled outside of the ISO, which receives those schedules in order to allocate transmission. That is done through a clearing price auction. All users of those interfaces pay the market clearing price or marginal cost to clear the congestion.

California has zonal pricing instead of nodal pricing. This goes to a fundamental question of who should make decisions about optimization. When you have a bid-based model that is optimized by a central agency, that agency makes the decisions about

optimization and dispatch. California opted for a zonal model which says, we're going to have large pricing zones. Market separation says that the ISO does not optimize between market participants' portfolios. They do those trades themselves.

The ISO has unbundled ancillary service markets. It purchases all of its reliability services from those markets in clearing price auctions. It does not own or control any generation, except for the liability must-run units. The capacity markets also have associated energy bids, which form the substance of the imbalance market. The real-time spot market is run by the ISO, to make up load forecast differences. The ISO runs a spot imbalance market, which is also a clearing price market. The ISO has additional responsibilities under the statute for grid expansion and transmission maintenance. On incentives, I take issue with the notion that the profit motive is necessary to provide incentive for proper behavior on the part of the corporation or its individuals.

The vision of the California system is one of reliability through markets. There were two trying summers soon after the ISO was launched. In the summer of 1998, the ISO had to make purchases when the capacity wasn't there. The summer of 1999 was characterized by a drastic, over 90 percent, reduction in all of those activities. There was very little out-of-market activity. Almost everything was handled through the markets. There was a significant maturation between the two summers.

California has taken some actions to improve grid system reliability and improve and expand the markets. There are some price caps in place. But an important distinction is that because California operates clearing price markets, every participant in a certain market gets paid the clearing price. That feature is worth noting in debates about market design and the effectiveness and viability of any kind of price cap. The caps were raised in October, recognizing market improvement. In any completely new structure, you have to expect to make design improvements.

California has done some contract reform of reliability must-run (RMR) units. Efforts are under way to reduce the number of RMR contracts between 1999 and 2000. One reason for this is transmission additions. Because those transmission constraints were created by the incumbent utilities, the costs for the RMR contracts are flowed through the transmission owners as an incentive to either weigh those costs or increase transmission. They see a proper incentive, and they are internalizing the cost of those transmission constraints by having to pay for RMR dispatch.

The Western States Coordinating Committee has started a reliability management system which fines control area operators and other participants for not complying with reliability criteria. There is movement away from dispatch through the old control centers to direct communication. We have seen a

significant improvement in generator performance with direct communications from the ISO to units that are providing services as opposed to through area control centers.

In terms of bid performance monitoring, market participants will perform at the level that you require. Bid performance monitoring is a large initiative under way after having a year and a half of spotty monitoring. We have also eliminated roughly a million dollars worth of payments to market participants based on that kind of performance.

There are several pieces to managing the grid. Long-term grid planning looks at the kinds of incentives that are in place for either market participants or existing transmission owners to build transmission. The ISO is getting ready to file a comprehensive framework to long-term grid planning which hopefully captures the right incentives and will put financial responsibility where it belongs. For RMR, the ISO has an annual competitive process that considers transmission and load.

The ISO incorporated a number of redesign elements in 1999. There was very little change in the cost of ancillary services as a percentage of total energy cost, which indicates that there has been substantial improvement in the procurement of ancillary services. A number of other market redesigns are in process now. Many of these have come from suggestions from market participants. Where you stand in the market drives

your opinion about market redesign. There is an entitlement mentality where, when you create any inefficiencies in the market, a segment of the market believes that they own those inefficiencies and that you're prohibited from fixing them.

In terms of TLR, loop flow curtailment, California uses a different version than the contract path methodology. All of the large paths in the Western interconnection are rated as an entire path, so the physical capability of each of those individual lines is irrelevant. The ISO's role is in smoothing seams, facilitating commerce, promulgating consistent scheduling rules. In terms of that future vision, I think that if the rules for the commercial models are sufficiently similar and the timelines and processes are uniform, we will be able to facilitate nearly invisible seams.

Speaker Three

I am going to give an overview of coordinating congestion relief across multiple regions. The context is thinking about regional transmission organizations and how they manage access and use to the transmission grid. A reasonable reading of the RTO NOPR will tell you that the basic structure for how to deal with this is to have a framework with bilateral transactions, financial transmission rights, license plates, access charges, market-driven investments. It is all built around the system of a coordinated spot market with a bid-based security constraint, economic

dispatch, and nodal prices. I want to address the seam and coordination issue. There isn't going to be a single region. So the time is well ripe to explain how you would put these things together and deal with these coordination problems across these various regions.

First, the notion that you can separate reliability decisions from commercial decisions is a myth, and is not possible. For many purposes, these are inherently intertwined, and we have to deal with them explicitly in that way. Second, everyone agrees that the TLR mechanisms we now have are not working and are causing more problems. The market redispatch pilot that NERC put on in the summer didn't work principally for the same reason that we have system operators in the first place, which is that this is a really complicated system. We need a coordination mechanism. So the question is how we can put together coordination of the NERC TLR process.

The basic structure now is that market schedulers provide information to the security coordinators, who use the various power transfer distribution factors to figure out what's going to be constrained. They come back with a set of curtailments to adjust, and send the information back to everyone in the market. We want to have a method of coordination across regions that deals with the seams question. We want to have a market alternative to substitute for that. I will try to illustrate a way to do that.

If you want to get a market-based system, you have to have schedules, bids and economic redispatch consistent with the efficient solution. The only way to do that without having the super-coordinator is to have an iterative process that goes between the system operators. There will have to be a settlement system. Most importantly, we will have to integrate markets and reliability. Having a coherent statement of how you could do this emboldens you in terms of thinking about what you can actually do to have a feasible mechanism that would allow you to do this kind of coordination.

There are three basic parts to this structure, taken from the existing TLR mechanisms, with some supplements. In the first stage, a market participant submits schedules and redispatch bids for the dispatch hour or whatever period we're talking about. Second, the system operators interact with each other. But they don't go back to the market participants; they are having a conversation amongst themselves, exchanging information much as they do now with the TLR mechanism. They produce a coordinated solution for congestion relief. The solution is consistent with the competitive market in terms of efficient outcome, getting the pricing right, and all the other kinds of things we want to have. Third, they publish that information for the marketplace, just like they do now with the TLR curtailments.

I want to use an example to show how this process would actually work. We have three regions. I will start with an

unconstrained market solution. This would be the equilibrium solution if there were no transmission constraints and we had an infinite bus. The price would be \$50 everywhere. But the system is constrained, and the schedule is not feasible. Each region has responsibility for the buses at the locations in their region and for the transmission constraints in their region. I have identified the limits on the flows on the lines. Many of these limits would be violated at the previous solution, so something has to be done.

The idea of this scheme is that the bids come to the regional system operator in regions 1, 2, and 3. The region 1 system operator worries about its constraints, but doesn't worry about the constraints outside the system because it doesn't know about them. It has a description of the flow so that it can get the power flows correct, but it doesn't keep track of all the interface limits and other factors external to that system. Likewise in regions 2 and 3. Also, the system operators are talking to each other and giving each other information, a set of adjustment bids, increments and decrements relative to the existing schedule. They say, we could increase or decrease generation at these various locations at these prices. They provide that information on a bulletin board, in effect, to the other system operators participating in this process.

Region 1 knows all the bid information that it has gotten from its local market participants. It has the real time information. And it has adjustment

bids from the other regions. It doesn't have all of the detail of all the bids of everyone in the marketplace; it just has some increments and decrements that come from whatever the other system operators in regions 2 and 3 in this case have told it. The idea is that the system operator in region 1 looks at the network and says, I have constraints in region 1, but I'm not going to worry about the constraints outside of region 1. I have bids inside region 1 that I know about. I have adjustment bids from all my colleagues. And that gives me a set of information about possible changes that I could orchestrate.

If you look at this problem, it is a bid-based economic dispatch problem of exactly the type that they have already solved. There is nothing that they have to do differently than what they currently do. The system operator in region 1 solves his problem for his region, using the whole grid. He takes the information from the others and figures out a redispatch of the system in order to get a new schedule. And he produces information about congestion costs.

Region 2 knows about its own bids, and now knows about the congestion cost in region 1. Analytically, all you have to do is take these bid curves and raise or lower them by the amount of the congestion cost. That produces another set of bids that region 2 is now looking at. The problem region 2 has is identical to the kind of problem that it already solves—it is another economic dispatch problem, with just an adjustment in the set of bids. Region 2

solves the problem to adjust for its constraints, but doesn't worry about the constraints of regions 1 or 3. But it has information about the congestion costs in region 1, which are internalized in the bids. It produces a new set of congestion cost estimates for its region, and publishes those on a bulletin board.

The next step is adding up the congestion costs outside the regions. That produces a new set of congestion costs. And we do it again. This is the conversation the system operators are having with each other. But suppose that when region 3 adjusted, it screwed up things in region 1. So you go through the process again, and the system converges. It converges to a solution that satisfies all of the constraints and prices, everything is internally consistent, and it is the same answer you would get if you had one system operator for the entire system.

All of this information is produced in very easy ways. It is the same software that people already use, if they're using software. The calculations are not complicated. The iterative method can seem scary because you have to do it more than once, but we're not talking about doing everything from scratch every time. We are talking about making modest adjustments against an existing solution.

How quickly does this go? Looking at the rate of convergence to the final prices in the example, it gets to the end solution very fast. This is not surprising to me, given experience

with other computational mechanisms like this. If the regions are large enough so that the external effects are relatively modest compared to the internal effects, then you get a mathematical characteristic, which means that these things will converge very rapidly. A similar mechanism has been tested by a professor at the University of Texas. PJM is already doing what we are talking about. PJM doesn't have the information from New York, but will soon be able to get it. So we are not talking about a huge innovation. The critical step is getting the congestion information from the others and shifting the curves the right way. Once you do that, the rest is pretty simple. The virtual ISO will achieve many of the benefits that we have been talking about.

Speaker Four

The three power pools in the Northeast have had a long history of coordinating with each other. There is an industry consensus model that the ISOs in the Northeast and others around the world are working towards. Some features of this model offer exciting alternatives to TLR. Given that, there are some things we need to do in terms of our existing practices that will allow us to take advantage of those opportunities.

The Northeast model has installed capacity obligations that the load must maintain, unbundled ancillary service markets and, in the case of New York, market-based ancillary services that are solved simultaneously with the energy market. We have congestion management in the case of New York.

The objective of these features is foremost to keep the lights on and ensure reliability. But we want our markets to be workably competitive, not necessarily perfectly competitive. We want to bring the benefits of competition to the marketplace now. We believe that the models that are evolving in New England, PJM, and New York meet that.

In terms of New York, approximately 60 percent of the load is in the greater New York City, Long Island area. So in operations, the focus is on balancing the system and bringing power from the north and the west into the greater New York City area. Typically, there is a lot of congestion. The New York market has a combined ISO/power exchange model with a spot market solved every five minutes and congestion management done via locational-based marginal pricing. A lot of time was spent to ensure that the bilateral markets and spot markets were compatible and that one wasn't favored over the other. The two-settlement system is an important feature. It is essentially a market-based way of ensuring that people do what they say they're going to do.

All of the Northeast ISOs have some of these features. It is a function of where the ISOs started from and how they evolved. New York will have many of these features, but does not have, for example, trading hubs in the initial ISO implementation. The other ISOs are working hard to add the pieces they are missing. I think that within a year or two, we will see very similar models in each of the three

ISOs. On our short list is trading hubs to improve the liquidity of the market, a congestion buy-through option, further enhancing bid and scheduling flexibility. New York, because of the metering available, is not doing full nodal pricing, but will.

In terms of the coordination objectives with the other ISOs, we are working on standardizing terminology among the control rooms so that when we talk about reserves, we're all talking the same language. We will be working on congestion management issues, as well as long-term planning and transmission expansion. Extending the use of new technology will be key to making a lot of this happen.

Since ISOs tend to also be security coordinators, we feel that ISOs should have a more prominent role in the committee structure at NERC. There is currently not a separate ISO sector that has voting clout, and that is something that ISOs would like to advocate. We can speak up and convey our point of view, but unless you have voting clout, it isn't the same. We have a concern that some of the solutions being developed in the short term not be mandatory such that they hamper us from implementing more elegant solutions.

In terms of the TLR problem, my assessment is that it's an apples and oranges problem. There is a scheduling and reservation system that is contract path-based, yet you have a curtailment procedure that is flow-based. They don't line up. We need to either go all one way or all the other. The physics

suggest that you need to go flow-based. With the new two-settlement system, if you could schedule these offpath flows on a day-ahead basis, you could use the two-settlement system to lock in your congestion costs. Furthermore, you could have hedging mechanisms, and hedge the congestion costs on that flow. What is holding it back is not being able to see this flow a day ahead. So you have to get the scheduling procedures lined up with the curtailment procedures. We plan to continue to refine these procedures and hopefully demonstrate their value.

The three ISOs use the acronym NICE (Northeast ISO Congestion Evaluation) for the alternative to TLR. We will try to demonstrate it in a modeling sense and then educate people and bring it along. The long-term goal of the group is to remove the seams. From the point of view of a market participant, you don't really want to know that there are three ISOs with different rules. You just want to move a megawatt from Boston to Toronto. That is what we are working towards.

Discussion

Question: What is the right number of ISOs?

Response: The basic idea is that for the major constraints in the transmission grid, you want to have those internalized in an ISO. Then the ISO will have responsibility for a region. You couldn't have an ISO for every bus. It is hard to know exactly

where the boundary line is. We should do some modeling simulations to find out. My intuition is that you probably want reasonably large regions.

Question: Do you see Speaker Three's system for coordinating congestion relief working with an independent transmission company model? What markets does the RTO have to manage for this to work? Is it just the congestion type market?

First Response: There are going to be multiple parties operating in the same interconnection. Those parties are ultimately going to have to figure out a way to interact with one another, even though they are internalizing within themselves their own business. I think this is a good way for them to coordinate the congestion issues that they are going to have to manage when it comes time to deliver.

Second Response: It is pretty clear that this would work if you had the ISO gridco model. If you had a wires only company operated by the ISO, this would work, as would a model where you put the gridco and ISO together and call it a transco, as long as you still have the system operator there, following the same rules. That raises the question of whether you could run a market in the system and get an efficient answer if the transco is handling system operations, and all you give them is broad price cap incentives as opposed to figuring out the rules for the system operator. I don't think that model has a chance of working. One, all of the other participants will be nervous about this.

They want to know what the access and pricing rules are. Two, if we knew how to set the incentives for a big monopoly so that they would do the right thing, we wouldn't be restructuring the industry. So the blithe assumption that you can give these transmission companies some kind of a profit incentive and then they will figure it out is ahistorical. So you can have independent transmission companies that are responsible for system operations, but you would still have to face all of the problems about how they run the balancing marketing, deal with congestion management and long-term rights, etc.

Comment: I am impressed by the extent of the New York ISO's regionalism. I had thought that New York wanted to go its own way.

Response It came down to a desire on the part of the member systems of the New York Power Pool to extend what they already had. There was coordination between upstate and downstate to alleviate congestion. We added security constrained dispatch in the 1980s. The ISO builds on the previous successes. It is a continual evolution.

Comment: I would take issue with the characterization of transmission as a monopoly business. There is a market power issue; there are captive customers. But not just incumbents can build transmission. I think that installed capacity is going to go away. There are other ways to preserve that reliability signal to generators.

First Response: As we move from the vertically integrated world to the market-based world, you do need an installed capacity market to ensure that we can make that transition reliably. If we set up the right market rules and have a vibrant, efficient market, eventually I think many would agree that the need for an installed capacity market will probably go away.

Second Response: If the transmission business is truly competitive, whoever offers the best deal should be able to construct lines. Incumbents have an advantage, but if we are talking about a truly competitive transmission business, then incumbents will probably be forming some of them. Who builds them depends on who has the best construction company and the best bids for construction. Who owns them depends on the transmission business. If it is a business that takes in the facilities by leasing them and then running them, then the owners are different from the operator. So there is no constraint from that point of view.

Question: How does California manage congestion in the day-ahead market? How does the balancing market operate?

Response: You get incremental/decremental bids from scheduling coordinators, then make adjustments and establish a clearing price for use of a constrained interface which all users of that interface then pay. If there is residual congestion in the day-ahead, that is managed through the imbalance market by essentially splitting the imbalance market and purchasing and

selling imbalanced energy separately in two zones.

Question: Are the ISOs doing anything to promote demand-side price elasticity? If not, where do we see that coming from?

First Response: I see that in two different contexts. One is the ability of demand to say that if I see a certain forward energy price, I wish not to consume. Structurally, the capability already exists, and demand could bid into the power exchange or other exchanges or in bilateral transactions to signal that demand. A piece of that loop that is still open is some PUC decisions with respect to the utility load. The other context is actual participation by load imbalance or ancillary service markets instead of the forward markets.

Second Response: The New York model has been designed to allow for demand resources, both for energy and ancillary services. With the two-settlement system, there are some opportunities that can be taken advantage of right away. There are mechanisms called price cap load bids that allow an entity to bid in to take, for example, an additional 10 megawatts of load in the day-ahead market if the price is no more than \$30. The ISO tells them whether the price is \$30 or not. If the price is less than that, they can opt out. There is also treatment of intermittent and renewable resources that is favorable and allows those resources to participate in those markets.

Question: On Speaker Three's methodology: Would it work if you had six to nine RTOs in the eastern interconnection communicating among themselves? Would you see them naturally gravitating toward this methodology or experimenting with others, or is this a methodology that is obvious to transmission operators?

Response: I think it depends on where they are in this process. If they are in fact running a bid-based balancing market, they are getting bids from the market participants and are getting the efficient solution and charging the prices. If they get into a regional model, then all the other bilateral schedules are handled in the obvious way. I think that once you work through this and have somebody demonstrate it to you, it seems like the natural way to do it. This method doesn't double count, unlike others that people have set up. But if you have the view that we can't have an efficient balancing market, then you won't see this as a natural solution because you don't have some of the components that would fit into it. If they do what the RTO NOPR says, this will seem natural.