Harvard Electricity Policy Group
Special Session: Transition, A Never-Ending Process
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RAPPORTEUR'S SUMMARY[*]

Morning Session: Getting From Here to There

Order 2000 sets out a target for Regional Transmission Organizations. That target is set forth in the context of a regionally diverse situation. In some regions, such as New York and PJM, reform, while not fully evolved, is at least fairly far advanced. In other regions, such as California and New England, while regional institutions are in place, they are still trying to make adjustments that improve operations and are more reflective of regulatory direction. In yet other regions, such as the Midwest, institutions are skeletal and there is considerable risk of fragmentation or serious implementation difficulties. In regions such as the Southeast and the Northwest, there has been little movement toward RTOs. Is more national harmony needed? Will voluntarism and economic incentives be enough to move the power market to where it needs to be in order to be viably competitive, highly reliable, and sufficiently predictable for prudent business people to put their money at risk and consumers to derive the full benefits of competition? As a matter of public policy, how sweet should the incentives be? What should be done if incentives and voluntarism prove inadequate? What substantive measures need to be taken beyond voluntarism? Do regulators have sufficient tolls at their disposal? Do they need new authority? If so, what? How do these questions play out in the various regions?

Speaker One

I would like to talk about the Texas electric industry. The legislature passed the restructuring bill in the

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summer of 1999, so we are in the process now of moving the ball forward both through activities at the ISO and through a significant number of rulemakings at the state commission.

The vertically integrated utilities in the state will all go through a process to unbundle to a competitive generation business, a transmission & distribution business, and a retail business. The retail business will actually have the interface with the customer. The statute prohibits the wire companies from selling electricity or other competitive energy services. That prohibition on competitive energy services starts this September. Everyone in the investor-owned utility world is in the process of moving those to an unregulated affiliate or just stopping anything that would be defined as a competitive energy service—audits, energy efficiency programs, things of that nature. This is unique from other states. The idea was to keep the regulated business the delivery of electricity.

The timeline is that rates have been frozen from 1999 through 2002, when competition will start. During that period where rates are frozen, any over-earnings are essentially frozen as well; they will go to write down stranded costs. There will be a pilot project that will start seven months prior to the opening of competition. That is a period of time when marketers and retailers will be able to go out and start interfacing with the market and attract customers. The pilot is limited to five percent of the load.

I think the essential element of the pilot will be testing all of the systems. Wire companies have to get systems set up to transfer metering information to the ISO. The ISO is in the process of developing a lot of systems. One of the things we hope to accomplish during the pilot will be testing all of the systems before we throw the switch, because when we open in 2002, it's the big bang approach. It will be all customers at one time.

Starting in 2002, the affiliated retailer-- the retailer affiliated with that wire company in that particular service area--will offer small customers (defined as one megawatt and less) a six percent discount. That discount will be available for five years. But it is really broken up into two pieces. During the first three years, it is the only price that they can charge small customers in their service territory. Outside of their service territory, they have complete freedom. If other retailers come in and start winning customers away, they are not able to discount to try to beat the market. It is a mechanism to try to help facilitate competition. The last two years of that five-year period, the price still has to be available in the marketplace, but the affiliated retailer is not required to only charge that price.

In Texas, municipally-owned utilities and cooperatives have significant political clout. They wanted local control over when they would start competition, and they got it. They will determine their own times and terms.

In terms of the T&D business, there

are some statutory requirements to manage reliability, e.g., call response time. The statute has about four pages dedicated to a code of conduct that is applicable to the wire company and how they deal with affiliates. The commission has recently expanded that through a rulemaking process. There is a rule with regard to conduct requirements to prevent cross-subsidy and market power abuses, and ensure that the wire company treats affiliates and non-affiliates in a like manner.

The wires companies will bill retailers for a non-bypassable delivery charge. The wire companies will not bill end-use customers. This is an important element. It puts the retailer in the position of dealing with customers. This approach prevents some duplication that I think other states have incurred. The non-bypassable charge is the T&D rate. It is also the system benefit fund, which supports low-income programs and some loss in school tax funding. Most Texas schools are funded through property tax mechanisms, and with the nuclear plants being devalued in this process, there is a shortfall in school taxes. There are also monies there for customer education.

The wires company also ends up with the responsibility to manage energy efficiency programs. The intent is that they will collect monies through rates, and then make those monies available to energy supply companies, retailers, etc., to go out and work with customers to reduce energy requirements. The money is targeted to reduce demand by about 10 percent a year.

For the first couple of years, metering will be done by the regulated wires companies. In 2004, metering will become competitive for larger customers, and it will probably be a bit longer than that before it becomes competitive for small customers. The legislation addresses metering very briefly; there is more work to be done on it.

On the generation piece of the business, Texas' legislators visited New England, Pennsylvania and California, and decided based on those visits that they didn't want a state agency-run mandatory pool. The statute essentially establishes a bilateral market. The ISO will have a balancing pool to balance the market hour to hour, moment to moment. But most transactions will be bilateral.

To deal with market power issues, there are capacity ownership limitations. No entity can own and control more than 20 percent of the generation capacity in any of the markets. ERCOT is defined as a market as well as the other regions. Another element to deal with market power is an obligation on the incumbent generators to auction off 15 percent of their capacity output for the first five years of competition. If the retail affiliate loses 40 percent of its small customers before five years, then this obligation comes off. So there is a connection with how many of the small customers the retail entity retains.

There is also a portfolio requirement on retailers to add 2,000 new megawatts of renewable energy by 2009. It will be done in a stair step fashion. Each retailer will have to demonstrate that they either have it under a contract or have trading credits in an amount that would be their *pro rata* share.

As for stranded costs, I think most of the utilities would say they have gotten fair treatment through the statute. The PUC will this year go through a process to define the value of stranded costs in an administrative fashion, and in 2004, the utilities will go through a market valuation method to ultimately define stranded costs. There is no requirement to divest. There are a couple of other methods where utilities can trade independent stock in the company and use that stock valuation to define the market value.

The retailer that is affiliated with the utility is the default provider. They have this obligation to offer the six percent discount for up to five years, coming off if 40 percent of their customers choose another provider. There are provisions, though, that say they can't go out and just dump or sell customers. The customers have to make that choice themselves. Those things relative to the 40 percent represent incentives for the retailer to support competition and not stifle customer movement to other retailers. There is also a calculation that penalizes in a stranded cost amount the utilities for customers that don't leave.

Provider of last resort service is probably the only entity that will have the obligation to serve. We are going through a rulemaking now to define how the commission will go out for bids. We are working to be sure that that doesn't raise the price—otherwise, it won't be the safety net the legislature thought. It should be a competitive operation. There are a lot of consumer protections in the bill.

The ISO has to develop a lot of systems and get its processes in place before we can move forward. The statute defined a stakeholder board in terms of parts of the industry they represent. The ISO will continue to have responsibility for transmission access. They are in the process of working with vendors on registration systems that will keep up with which wire company is connected to which customer. They are working with vendors on the settlement systems, including the congestion management program, as well as the auction systems that the ISO will use to auction the various ancillary services and for balancing energy. Along with that, they're in the process of collapsing the 10 control areas in ERCOT into a single control area.

It was determined that the ISO couldn't deal with hundreds of people calling and scheduling power with them. So qualified scheduling entities (QSEs) will provide fully balanced schedules to the ISO. The ISO will conduct competitive auctions for ancillary services. There also has been agreement that these QSEs make up to 70 percent of their own ancillary services available to the ISO.

There was a political compromise on congestion management. Initially, if there is congestion, generators within a zone get paid a common price through that balancing market. Retailers will pay a postage stamp. It will be uplifted across the ERCOT market. There are some trigger mechanisms where if those costs hit a threshold, we will migrate to a scheme more related to marginal cost, looking at commercially significant constraints and charging those costs to the users of those constraints. Once we migrate to a more commercial model, the ISO will begin to auction transmission rights as well.

Speaker Two

I am going to talk about transmission. One of the key issues is size, not just geographic size, but number of megawatts, number of other entities. My company is in four southern states, with five separate operating companies. We have a big transmission system. There are two major ties, and several that are smaller.

We're not as far along as other regions in terms of ISOs. But we were at the head of the pack in terms of filing tariffs for comparable service and establishing our OASIS. Our standard of conduct is sound. We unbundled functionally--both organizational unbundling and generation planning. We have an active and growing wholesale market in the region. There is some retail competition in the region, but it is not complete, partly because our rates are below the national average.

We have looked at several options for transmission. Whatever we do, there will probably be some increase in transmission costs, since rates in the region are currently 17 to 20 percent below the national average. With corporate unbundling, you can have an affiliate, and that leaves all the questions about how separate you really are. If we are going to do something, we want to address that question clearly. There is partnership, but we feel that ownership and operation really should be together.

Divestiture is an option. One way is to just to sell the assets. That has problems. The value of our assets is about 1.5 times book, so if you sell that book value, you've immediately taken a hit. Then if you sell at, say, twice book, you have a lot of tax considerations. Another way to do that would be to spin the assets off into a new company to the existing shareholders. That is an option that is of a lot of interest to us right now.

The current position is that functional unbundling is working. That is debated a lot, but it is not broken to the point that you have to rush out and do something unwise. We want to protect the current pricing and recovery that we have for our region and for the shareholders.

Today, the transco appears to be the best option. The transco we're talking about is a for-profit, FERC-regulated regional transmission company. This company would own and control the transmission facilities in the region. It would not be controlled by any market participant. It would be driven through appropriate incentives to minimize cost and all of those things that a company has to do. We indicated in our compliance filing that we would comply with not having a two-part rate, but we have not submitted the revised tariff itself.

If you're going to have multiple RTOs, as I believe there will be in the Eastern interconnection, there will have to be coordination among seams. Whatever the structures shake out to be, they will have to deal with planning and coordination of operations. They will need congestion management solutions and an appropriate ADR process. It will be important, particularly to advance a larger market while having multiple RTOs, to have some type of pricing reciprocity provision. It is a question of how you can create a pricing algorithm between two entities that would reduce embedded cost charges. One way to do that is to have a load-based pay situation. If there is pricing reciprocity between the two RTOs, the load pays the embedded cost transmission, and that's all he pays. The other RTO might offer the same kind of situation.

Offering pricing reciprocity might create the ability to have many more transactions and maybe new introductions of congestion. One thing that might be considered is the ability to provide for incremental pricing for new investment to alleviate that type of congestion. The Alliance RTO, with its size and scope, has the ability for customers within it to seek generation sources that total some 72,000 megawatts. If you add pricing reciprocity, and let's say the Alliance entered into pricing reciprocity with the Midwest ISO or PJM, you could expand the marketplace for customers to have choice, even over a much larger area, for reduced transmission charges.

There is a lot of merit to volunteerism and flexibility in terms of how some of these structures go. Over time, I think the best types of structures will ultimately develop and survive. Looking at transmission from a business perspective, I think it provides for a good long-run solution in terms of making sure that there is investment being made in the grid. The policy in Order 2000, with some of the pricing incentives and concepts of alternative pricing methods, sends a positive signal to the investment community for future investment in this asset.

Regulatory and policy issues include cross-subsidization—concern about loss of input and influence. Another concern is permits for new lines: Who has the rights of eminent domain? The politics within a state can greatly affect whether you get a line inside it or not. Other issues are financial incentives to encourage investments, and pricing, incremental versus average cost. Who pays for that addition? And what rights go with that payment? And reliability enforcement authority.

Other issues include reactive responsibility. Who should have responsibility for it? In our region, there are a lot of non-FERC-jurisdictional companies. Some that are part of the security coordinator don't have any separation of their merchant and transmission functions, so there is less security-related information that can be exchanged with them. Computing needs and the automation of transactions overall is a big concern for us.

Speaker Three

I would like to talk about the California ISO in the context of how it meets the RTO functions and characteristic requirements, and some of the issues that will need to be addressed as we move forward in California to fully comply with Order 2000. In most aspects, the ISO fits very well with the requirements of the rule. There are a few areas where it may or may not, and a couple where clearly it doesn't appear to comply. But activities are in progress to address those.

There are five areas of change that I anticipate. One is responsibility for rate proposals. The rule talks about the RTO being responsible for proposing rates for transmission service. Second is the appropriate scope and regional configuration of the ISO. Third, congestion management is an area of intense focus right now within the ISO. Fourth, authority over interconnection requests, and fifth, transmission planning and expansion.

In California, the ISO tariff delegates to the participating transmission owners (PTOs) the responsibility to propose rates and collect revenues from customers. We have license plate rates today, although the ISO is currently considering a proposal that would modify that rate structure to move to a grid-wide charge for at least a portion of those transmission costs. Even in that new proposal, however, PTOs would still be responsible for proposing rates and continuing to collect them from customers. Will that current regime of responsibility for rate proposal and collection of revenue be sustainable?

Another question as to the grid-wide charge is whether in fact that is a mechanism that supports expansion of the ISO in terms of its scope and geography. There are many areas that would not look favorably on cost shifts associated with a grid-wide charge, and it may be a deterrent to expanding participation in the ISO. The proposal would move to a split rate, a local rate that would apply on a utility-specific basis, and would continue to be license plate-oriented. That grid-wide regional rate would be implemented over a 10-year transition period. It would result in cost shifts between new and existing PTOs. The proposal would set a cap for that cost shift at $72 million per year, spread between the three existing PTOs.

The mechanism would not be implemented until new PTOs--primarily munis within California--begin joining the ISO. The investment in new transmission would be treated on a grid-wide basis for recovery purposes. The requirement would be that new PTOs that come into the ISO and benefit from this cost shift be required to use any cost shift payments to reduce their existing transmission revenue requirement in order to minimize future cost shifts.

A number of benefits are claimed: Reduced grid management charge, which is the fee everyone pays for ISO overhead and operations; elimination of congestion due to existing contract transmission capacity; greater municipal utility participation in the ISO markets; and no FERC review of the public power PTO transmission revenue requirement.

The second area of need for change is scope. There is a lot of sentiment that California is not a big enough ISO or big enough to be an RTO. There are two dimensions to that. One is increased participation within California in terms of municipal utilities. The second is expansion beyond California. The legislation that set up the ISO and subsequent legislation does support and encourage expansion beyond California. It sets up a structure that can accommodate oversight of the ISO from different states. Part of the transition could be to identify what is costly or complicated, and ask whether the ISO can address those in a way that would respond to other states' interests. A number of other states have their own separate legislative mandates for Independent System Administrators (ISAs), for example, as opposed to ISOs.

The munis have a lot of hesitancy about the additional costs that they would incur from joining an ISO. They have concerns about the tax treatment of their tax-exempt-funded facilities, which still has not been resolved. Another of their concerns is that they look at bringing their transmission into the ISO and feel that they're not going to get full compensation for that. They think they lose scheduling benefits relative to their existing contracts and tax treatment. Even with the proposal as it stands, there has not been support from the municipal community for this access charge proposal. Frankly, there hasn't been broad consensus support from all of the stakeholders.

Let me say a word about the Western Interconnection organization. This is an effort that has been underway in the last couple of years to look at consolidating the Western States Reliability Council with the three regional transmission associations in the West to better integrate the reliability and market interface functions of each of those organizations. It is intended to align with the direction that NERC is taking towards establishment of affiliated regional reliability entities under the proposed federal legislation.

The third area that needs to be addressed is congestion management. Today we have an inter/intra-zonal congestion management mechanism. It is fundamentally flawed and needs to be overhauled. The ISO is at the beginning of a process to identify the scope and type of changes needed to fix the congestion management mechanism. October is the target timeframe.

We are looking at intra-zonal congestion management, where there are gaming issues; trying to get improved locational prices; and local market power. We are looking at the treatment of non-PTO transmission capacity, which is not subject to ISO scheduling, but which is affecting congestion. Non-PTOs had transmission entitlements on a number of PTO transmission lines, which was set aside to honor existing contracts. As a consequence, it's not part of ISO scheduling. Congestion sometimes is identified in the day-ahead or hour-ahead markets as a result of that set-aside. That is sometimes phantom congestion, because in real time, that set-aside capacity is not fully used.

The fourth area is authority over inter-connection requests. Today, under the transmission owner tariffs, inter-connection requests go directly to transmission owners. The ISO has input, but no direct final say—except, as the grid operator, it needs to clear the closing of any breakers in the final interconnection. I don't think there is likely to be disagreement about that responsibility being moved to the ISO. The main thing is protection of the assets of the transmission owners.

What is the responsibility of new interconnectors to mitigate congestion that results from their proposed interconnections? An example is the Palo Verde nuclear plant in Arizona, just west of Phoenix, a 3,800 megawatt generating facility. Six new generating facilities that have proposed interconnection in that region total 8,800 megawatts. Each of these plants is proposing to tie into the Palo Verde switchyard, but the existing transmission capacity is unable to handle all of that additional power.

What's the solution? The first is to rely on congestion management protocols. But there is a seams issue, with an ISO on one side and Arizona ISA on the other, with different kinds of congestion management protocols. It also doesn't address the issue of the need for additional capacity. The second option is for the new generators to build transmission to meet an incremental export need. But most of them are saying that their projects can't support additional transmission costs. The third would be for the transmission owner to build transmission to facilitate that competitive generation market, and to make it possible for generators simply to compete on the basis of price. A possible fourth option is that not all of the proposed generation will get built. Similar questions are being struggled with in other parts of the state.

Today the ISO and the transmission owners share responsibility for transmission planning and expansion. The transmission owners perform an annual assessment to the ISO's request. The ISO reviews proposed projects and generally has to give its approval to proceed. So there shouldn't be a lot of problems in making a transition to where the ISO is responsible for planning and expansion, as the RTO rule outlines. The questions are what obligation a new line has to mitigate impacts on existing projects and uses, and how to make trade-offs between transmission and generation as alternatives in that planning process.

You may have heard of the Alturas Transmission Project, which provides 400 MW of transmission capacity from the California-Oregon border to Nevada. The debate is that the 400 MW rating could reduce by 400 MW the import capability from the Northwest. There is currently litigation before FERC as to what is the responsibility of Sierra Pacific to mitigate its impact on the existing use. Again, this is a seams issue because there are different rules in both domains, and there is a need to bridge different protocols.

Trade-offs between transmission and generation are becoming a more difficult question as we look at the planning and expansion process. The RTO requirement is to build necessary transmission expansion. But what does the word necessary mean--is it necessary just in terms of reliability criteria, or in response to congestion or price signals that generally identify those needs? A question is whether FERC would allow recovery of generation project costs in transmission rates.

Speaker Four

I would like to focus on the transition as it relates to the formation of an RTO in the Midwest, the Alliance RTO.

Considering transmission as a business, and particularly as we make the transition to the RTO, we have been strong advocates of four principles which we feel are important to have a viable and sustainable independent transmission business, which we see as a transco. One, the resolution of all of these transmission issues should be market-driven and business-based. Two, there ought to be voluntary development of these transmission institutions. Three, continued flexibility of the market to determine the structure of RTOs. Four is the importance of the ability to provide for transmission expansion.

We have looked at transmission as a business. It is our intent to exit the transmission business, and we have taken a number of steps to position our transmission assets to be in a position to do so. In 1998, we established a separate transmission business entity for transition. We began the process of transferring assets from our vertically integrated operating companies to a separate entity. We made filings and received approval from FERC to transfer the assets. We have gone through engineering and financial analysis to create that asset separation. We have also worked on the financial side to deal with things like unwinding the various aspects of our mortgage indentures.

On a parallel basis, we have worked with the Alliance, which is a transco-based regional organization. The Alliance RTO consists of five companies that came together and last year made a filing with FERC. The companies are American Electric Power, Detroit Edison, Consumers Energy, FirstEnergy, and Virginia Electric Power. In December, FERC gave Alliance conditional acceptance and authorization of various aspects of the filing under the ISO principles, as well as providing some guidance under the new RTO rule. One issue that came up in the compliance filing was the rate format. Alliance had suggested a two-part rate, with a zonal charge and a regional access charge. FERC had some concerns, and directed us to come back with a different rate format.

In setting its organization and structure up, Alliance came up with a vision statement. It picks up on the concept of the business approach, the transco-type model, and creates flexibility by providing the ability for a company to trigger the transco by divesting its assets, creating an independent entity that would own and operate those assets but also could operate the assets of others who chose not to divest—in a sense, be the ISO for those other entities that weren't at that time ready to put their assets into the transco. We felt that was important because it provided the opportunity to create the business structure, but also to create a larger entity with not everyone having to divest.

My view of the perfect world would be if you created an independent company, absolutely separate from generation, that owned and operated all those assets over a wide area. But that can't happen overnight. One thing the Alliance model provides is the ability for companies to think through where they want to put their assets or how they want to handle their transmission investment.

Issues in the Midwest include the marketplace desire for a competitive, efficient market and an efficient congestion management tool; evolving regional markets; and dealing with multiple transmission entities, including non-participating transmission owners. With seams issues, we advocate looking at different kinds of possible structures. Larger markets may be a way of dealing with seams issues. Dynegy has made a proposal for an overarching organization over ISOs that would deal with seams and reliability issues.

The Alliance proposal contains an inter-RTO cooperation framework. In order to facilitate super-regional transmission reliability and competitive generation markets, Alliance proposes to develop inter-RTO cooperation agreements to participate in coordinated regional planning, coordinate operations, develop comparable transfer capability determination and posting, develop market-based congestion management solutions, participate in alternative dispute resolution, reduce embedded charges for inter-RTO transactions, negotiate a long-run pricing structure, and provide for incremental pricing for new projects.

In summary, a voluntary, flexible approach will be successful. A business-oriented resolution, flexibility, and incentives are key.

Discussion

Question: Who ought to be defining the geographic scope of the RTO?

Response: We think the entities in the region should have a big hand in defining it. In our region, there is a natural size, and we think that if we try to expand it considerably, it is likely to fail for that reason alone. There is at least one ISO that was started with an area that was too large to work, and it did not come about predominantly because of the size issue.

Second Response: With Alliance, there were five companies that had a common philosophy on the transmission business. At the same time, we were all interconnected, and there are trading patterns within that organization. Over time, that configuration or the participants could change. If folks feel that the market needs to be broader, there are ways to accomplish that through coordination and types of pricing parameters with reciprocity for transmission.

Question: A couple of panelists made the point that it is important that ownership and operations be together. The other view is that we're going to have coordinated or single operations, but ownership of the actual assets by lots of different entities. Is there a difference?

First Response: There is a difference, but it's not day and night. We just believe philosophically that it's better to have those that are predominantly in the transmission business be the ones that make the major decisions about transmission expansion. Whether it is for-profit or not, they at least have some interest in appropriate operation.

Second Response: As an entity where we own the assets, but the ISO increasingly makes the decisions about how those assets are used or expanded, I'm not comfortable that that is a long-term, sustainable relationship. One concern is whether the ISO could decide to sponsor something that the market had not chosen to pursue. This raises a fundamental question about who is responsible for the commitment of financial investment. There is also continuing concern that many of the operational dimensions in terms of efficiency and making decisions through a least-cost approach are not driven as hard as if they were a for-profit entity. The non-profit ISO concept sometimes also runs into that problem. I think there's probably a longer-term role, where control and ownership are better combined.

Question: Have you thought about what happens to the lost economies of scope when you rip the transmission from the distribution, and how you deal with the fact that the distribution system may be more expensive to run, and how to deal with union issues?

Response: We had to confront that issue when we created a subsidiary. We ended up negotiating between the transmission business and the distribution people an operating agreement where the distribution folks would continue to maintain the transmission facilities for that subsidiary for a three-year period. It gave both parties a chance to make decisions about union issues. There are synergies in a vertically integrated utility that you may lose with a larger, regional, independent transmission company. But maybe you can get some of it back by virtue of now having horizontal synergies between transmission and maintenance crews.

Question: There are two ways to understand the experience in California with municipal rights—as evidence that the market wasn't able to deal with this problem because they didn't trade them outside the ISO; or that they were exercising market power by withholding the physical rights. What happened?

Response: Either of those could be the motive. The market not working is probably part of it. The municipal utilities, though they have transmission capacity that is set aside outside of the ISO congestion protocols, do have an OASIS and the ability to market that transmission. But that hasn't been happening. Perhaps parties seeking transmission prefer to deal directly in a one-stop-shop sense with the ISO. The other thing is that the munis look at their existing rights, giving them a lot of latitude to exercise transactions up to 20 minutes before the hour, and are unwilling to give that up. That puts the ISO in the position of not being able to use it in any of its forward markets. The result is phantom congestion.

Question: When you create a transmission system structure, you affect the distribution system structure. You have a distribution company that is now a wires company, and since it's an affiliate operating under a code of conduct, it is indifferent to who's supplying the energy. The wires company is also relatively low-risk, and therefore needs a rate of return that is not very high compared to the generation side. You also require it to do energy efficiency. How is it going to recover its costs, assuming it collects on a kilowatt hour basis?

Response: In a perfect world, you could probably charge out distribution on a flat fee per month to different types of customers. In Texas, with a six percent reduction, I don't see distribution rate design changing a lot. Eventually, it could migrate to some kind of a monthly charge.

Question: At least two of the panelists expressed clear preferences for transcos. How do you see the transition taking place from reliance on retail customers and rate-based pricing, where retail customers pick up all the residual revenue requirements of the grid, into a system where, as a transco, you rely on transmission revenues, as opposed to the traditional rate-based formulation? How do you see transcos playing out in regard to state siting statues that focus primarily on the needs within the state, and also a few court decisions, as in Mississippi? How would a transco function in that kind of an environment when it needs system expansion?

Response: It is going to be difficult. In a transition from rate-based transmission, we would have to provide some assurance to our state commissions that their transmission rate won't go up appreciably more than what they would have absent this change. The real trigger point might be whenever retail competition is instituted in a region.

Question: With regard to the transco, how would you address seams issues? How would you handle things outside of the traditional service territory?

Response: There has been a lot of planning coordination across the regions. If you can't address issues with agreements between the various RTOs, the only answer is one RTO. Then you've eliminated the seams, but not the problems. In fact, you may have exacerbated them. There are geographic features that make for differences. You have to coordinate.

Would you have mutual agreements so that you have some rate concessions between each other? That is a matter of a business deal.

Question: Once we've made the transition to full retail competition, who will own the capacity rights on transmission? Right now, customers are clearly responsible for the revenue requirements demanded by the vertical operation, but if an industrial customer goes off on its own, would that customer have rights, or would the distribution company still have rights?

Response: That came up with us in setting up our subsidiary. Under the current structure, the subsidiary provides transmission service for all customers, bundled or unbundled. To the extent that most customers today are bundled, we take network service from this separate transmission company. The subsidiary operates under the terms and conditions of the open access tariff approved by FERC. With the unbundling of these customers, do those rights automatically transfer in the sense that a bundled customer had transmission rights under the current provisions? Or does that customer have to get in the new queue? I could see there being a case for those customers having the ability to continue transmission service as opposed to getting at the end of the line. It’s a good question.

Afternoon Session: Market Turmoil, Trading, And Risk Management

Under the best of circumstances, with well-designed market institutions and common rules, an electricity market will, inherently, include a great deal of volatility. During the transition period, that volatility, or at least the anticipation of it, is likely to be increased. Recent experience certainly suggests that exposure in the market exceeds that which had been experienced in the regulated environment. Traders are very active in the market, but they confront the reality of a business landscape characterized by only partially evolved institutions, uncertainty and instability in regard to the rules, a constantly changing cast of actors in the market, and the promise of a fully viable market not yet fulfilled. All players in the market need to manage their own risks in the new milieu. Some, accustomed to the regulated arena, find that challenge to be daunting. Many continue to look to the regulators for some level of protection. The ability to structure trading relationships as well as to assure market liquidity and transparency all interact with the process of market design. How, then, do trading and risk management assist in the transition? Do they assist or only complicate matters even further? What types of hedges in the current state of the market really work to reduce risk? What types exacerbate them? How will hedging and risk management change as the market becomes better established?

Speaker One

Electricity, in most places, is an immature, fractured market in time, with wildly varying prices, and in geography, because you can't move the power from one place to another easily in many parts of the country. Unless we get liquidity in the trading of transmission, we can't get liquid energy markets. We have many small energy markets that aren't hooked together. Physical delivery is crucial. Unless we have good underlying physical cash markets, we can't build good financial and futures markets.

What do we do about it? We have a solution, which is that we can apply the fundamental ideas of commodity markets, but use intermittent technology and take it down to the fine level of detail required for electricity. The challenge is to create markets for electricity and to make markets do the job of running a power system.

The vision is of automated electricity markets built on top of the existing grid. Any buyer ought to be able to transact with any seller. The system operator has the principal focus on reliability. There is the concept of a clearinghouse, which needs to be both physical and financial. Clearinghouses are ways to standardize contracts and make sure we agree on contracts in real-time. There's a need for power market services, whether bilateral or power exchange. There are other products that need to be purchased and sold, like ancillary services. Again, can't we define these in such a way that we can trade them just like any other commodity, rapidly and simply? We need automation.

Who participates in this market? Interactive bilateral traders over the telephone, entering it into computers for confirmation, or automated exchanges which run 24 hours a day, seven days a week, much like e-trade or the New York Stock Exchange. Imagine a thermostat on the wall that can see the current price of electricity for next five minutes, the next 50 minutes, and decides that the price is too high now, I won't turn it on until the price drops. Or an air conditioner. When I say power market services, that also includes basic power procurement—selling and buying generation.

We have been working on a single platform that can handle all of this, one dot-com Internet-based platform. We launched it a week ago and are beginning to apply it.

How do you organize transmission? The contract path method is not a good model because of the loop flow problem. There is another way to solve the loop flow problem. I call it the flow gate method. It's similar to what NERC has been working on for a number of years, but with some substantial differences in implementation. If I go from node five to node 11, power will flow across all paths. How do you predict where it's going to flow? You can run a power flow model and compute that. They will give you factors that tell you, if I go from five to 12, how much flow goes across each case. In some cases, you produce counter-flows on the interfaces. Are those factors stable? When you have an additive model like this, and stable flow distribution factors or transfer distribution factors, you have the basis for a very simple market model.

Because you are taking account of all of the parallel flows, you don't have the problem of calculating, adjusting ATC for loop flow. You don't have the problem of adjusting ATC for other transactions. If somebody does a transaction that produces a counter-flow, as soon as he schedules that transaction, he can sell to somebody else. Now you can do all of this without any markets.

The next step is, can you automate it? To automate it, you set up each of these flow gates as markets. Somebody has 50 megawatts for sale at $25, and somebody else buys it. You trade these as a commodity. That produces forward prices on these flow gates. You have a bid and an ask price for next week or next month or next hour. If you know the price on flow gate A, flow gate C, and flow gate B, and you know that for your particular transaction going from five to 11 what the waiting factors are, you can compute your point-to-point price. This simplifies the underlying trading model. It's transparent.

Question: I get the impression that you believe that the number of constraints are relatively few and that it's possible to know where they're likely to be. I work under the assumption that they frequently are many and unpredictable. Does this system rely upon being able to know where the commercially significant constraints are?

Response: You can add new constraints. Or if you have a local constraint, say, into San Francisco, if I'm going from Bonneville to San Diego, I probably have no impact because there's no flow on that. But if I'm going from Sacramento to San

Francisco, I'm certainly going to have to purchase rights on that flow gate. Texas went to commercially significant constraints, which is a great step forward. What's wrong with the Texas market is that they created zones between them. They didn't recognize the nodal model. But you don't want to do it all through central dispatch. You want to do with forward trading markets as long as possible, until the point you have to switch over.

Speaker Two

One of the questions that we have lost sight of is, Where should the regulator be involved in these markets? Are we creating risk with some of our rules?

What kind of price signals do we have? If you open your *Megawatt Daily*, the prices reported are what I call structured whispering. Nobody knows exactly how those prices are created. There are also a lot of debates about liquidity. But what I worry about is that poor market design, the exercise of market power, and poor information are creating risk in these markets.

What we do in these markets is create fictions. We've created our share of fictions in these markets in order to facilitate trading. For example, we have bilateral trades. We know that nobody really trades bilaterally. We create these fictions to, hopefully, lower transaction costs and make the market simple. Another fiction is vertical demand curves, which we place in these ISO markets. A lot of people are arguing that you have to be able to withhold power from the market in order to recover capital costs.

A lot of these arguments assume that the markets are never going to fail. The California ISO deals with the market power problem by assuming a larger market than really exists. The California PX was created to send out market signals, but it turns out that a lot of the market signals it sent out are from infeasible trades. My conclusion is, don't over-fictionalize.

Measurement is very important. If you can't measure, all you can do is theorize. One of our biggest problems is that we've institutionally evolved these markets so you can almost not measure them. Even if you could measure them, what we have are contracts with large industrial customers that aren't contracts at all. They're compacts. We don't know the quantity they're buying.

Why should a regulator be in the business of regulating the market? There is a list of things from classical economics. If there's a public good, if it's a natural monopoly, if there are externalities, either positive or negative, and if the information is not readily available, there are arguments for government intervention in order to make the market work. How does that translate? These markets don't have an institutional history of competition. Most of us believe that transmission and distribution are natural monopolies. One of the problems with bilateral transactions is that if they fail, they don't fail on their own accord. They create the potential for huge externalities. They could bring down the system. So I think there's a strong argument for the regulator, because of basic principles of market failure, to be in the business of reliability and real-time markets. Price transparency is a secondary criteria.

What is liquidity? I think a good way to look at it is, Can you go to the marketplace and transact quickly, and know that when you go there, there isn't just one seller or one buyer who is your sole counterparty? Marketers can increase liquidity by helping people find someone to buy or sell with. They can also directly inject liquidity themselves. They also provide the role of price discovery. If something isn't really traded, it's hard to say that it has a real price we can all agree on. By helping facilitate trading, we can say, well, that looks like a good price. It also helps to drive price closer to value. Finally, they can provide risk management products that cap your exposure to some extent.

I would like to focus on transmission as being a real problem. Most discussions seem to separate generation from transmission, but of course they are closely tied. One large problem is the uncertainty of transfer capability. If you go to an OASIS site and look to see what the transmission provider is offering, sometimes the numbers are very low and somewhat questionable. There is also the problem in many cases of a very arbitrary congestion management practice. You will find TLRs called on flow gates well below the posted limits for the claimed flow. At other times, nothing will be said when the posted flow is way above the limits. There is also a lack of non-discriminatory open access to transmission to a lot of markets. Some of this is rooted in so-called native load exception or bias. And because of restrictions on what kind of price you can charge for the resale in transmission, there is in effect no secondary market for transmission.

What does this mean? It reduces transmission liquidity. In some cases, it is very difficult to buy, and in others it is practically impossible to sell. That is a good definition of poor liquidity. And this reflects on the generation side of things. If I cannot get generation from A to B, and I really want the power at B, I will be hesitant to buy anything over at A. So my ability to move power affects how desirable buying power out of the marketplace is. Also, I lack full ability to mitigate some of my risks. Because of ineffective implementation of TLR or other transmission congestion management techniques, I have a difficult time ensuring that I can deliver something or putting on a proper hedge that I know will stay through to the end. That leads to credit and counterparty uncertainty issues, which hurt the market.

What should we do about this? An important step is to have genuine non-discriminatory open access to the grid. First, by eliminating this native load preference that's built in to most systems. Then requiring everybody who wants transmission to compete fairly with each other for it. There also needs to be an improvement in transmission capability predictability. Information about limits and how much is available needs to not only be accurate, but timely. There can be situations where a limit has been changed for hours, but you won't necessarily know about it unless it directly affects a transaction you have going on. Planning becomes impossible. And we need a functional secondary market for transmission to allow the resale of transmission at market-based prices.

Liquidity is the ability to buy or sell at market quickly. It's not the total sales volume in the bilateral market. It's not the turnover. And you measure it from the time you decide to trade to the time you trade at market price. Which is a more liquid system of markets, bilateral with locational marginal pricing (LMP) or bilateral only? Bilateral with LMP wins hands down on the liquidity question. Another problem creating risk in these markets is that we have not yet gotten transmission rights into the system and institutionalized.

In Order 2000, the ISO is responsible for short-term reliability, congestion management, ancillary services and real-time balancing. If you put all that together, you need to design markets. Simple markets fail. Zonal markets end up with lots of uplift. Sequential markets, that is, selling ancillary services one at a time, end up with serious arbitrage opportunities that don't get fully taken care of. And requirements to bid in these markets, start-up and no-load costs, create non-convex cost functions. Convex bidding prevents marginal cost bidding and raises the risk to the market participant.

A market design that works would have pre-day ahead markets, where you sell congestion rights, even options contracts; would deal with market power, which in fact every ISO deals with in some way; would allow marginal cost bidding; would have bid cost recovery for dispatched units; would allow self-scheduling; and would, as part of bilateral trading, allow people to bid, with limits, on ancillary services and congestion. For example, they can put in a bilateral deal and say, I'm willing to pay up to a certain amount in transmission costs or don't take the deal. That ends up as what I call a simultaneous nodal market clearing auction. The system operator needs to clear the market simultaneously, and at the nodal level.

A lot of people think market power mitigation is created by a first-price auction. A first-price auction creates additional risks. For entities that have significant market power, you can have a marginal cost bid cap. They are required to bid in at approximately their marginal costs. They get market clearing prices. This is not a punitive strategy.

Speaker Three

There are two underlying issues that we've been talking about all day and that underlie the thoughts that I'm going to share. One is that reliability can't be separated from market structure. We don't worry about whether there is going to be milk at the grocery store because we have confidence that the market system, through the pricing mechanism, will result in the things we need being there. Similarly, as we argue for greater free markets in electricity, if we want the most efficient allocation of capital and complete markets, the pricing mechanism will have to adjust to ensure that supply equals demand. The other thought is that, in all of these markets, as in commodity markets in general, you have to ultimately have convergence of the physical and financial market. To develop a market system where that convergence happens best should be the goal.

When we look at how markets develop--and electricity is no exception--the least free market is the cost-based, completely regulated market. The goal from a financial perspective, and presumably from an overall market efficiency perspective, is to have the most liquid market available, so that there are the most people able to transact, the prices are there when you go there, etc.

You can trade to some extent regardless of the underlying market structure. But the types of markets or types of products that you're going to be able to trade will be limited if there is no transparent hourly market, as opposed to the pool structure, where you do have that transparency that enables you to create a much broader spectrum of products. So in building market structure, we are looking for one that enables the price discovery mechanism to be the greatest.

To my mind, PJM's western hub is the most liquidly traded point, probably in the world, certainly in the United States. The convergence of the physical and the financial there is what we are ultimately looking for, because of the flexibility. The problem is this trade-off between stability of a regulated market, where prices are relatively static, and this incredible market volatility that we've all become aware of in electricity. You can't have both.

Looking at the last two summers, there are a couple of reasons why we are experiencing these high prices. One is that until the end-use customer receives the same market signals as everybody else, nobody has an incentive to behave in a rational economic way. So if prices at Cinergy are $7,000 and I have my air conditioner blasting because I'm not paying for it, what's the point? You're not going to get reimbursed by the utility or anybody else if you turn down your air conditioner. Since airline deregulation, we have different prices based on the true cost of service. People are receiving the signals. In electricity, restructuring will result in occasional extreme pricing, and this causes huge problems if you can't pass that on to a customer.

So utilities are put into a position of having to manage this risk, which is not the most natural thing for them. As the utility is facing the volatility of the marketplace, the question becomes, should they develop a trading function, as a dealer, and go out and trade in commodities markets as a profit center, with the idea that they're going to make money independent of the natural positions that they have? And, if so, what are the issues they're going to face in terms of setting up a system that's effective? Or is the utility going to recognize that there is a function that's going to force them out into the marketplace, either to sell their generation into the marketplace or, if they're a load-serving entity, to procure electricity? And how do they deal with the exposure that results?

The main drivers in the catastrophic situations that we've observed are credit or lack of awareness of credit, of the counterparty, the controls that are necessary to have in place to trade without taking on exorbitant amounts of risk, and the contracts that need to be put in place that are effective and that prevent default or unreasonable risk.

All of us are going to be facing volatile prices. What do you do about it? For most of us, the answer is, you hedge. And it's important to recognize that in hedging the position you're going to reduce the expected value of the company overall, but you're also going to mitigate your risk. So ultimately the point is that in a working market it's possible to buy and sell, and delivery is assured, so the reliability issue becomes secondary to having a functioning market. You are going to face volatile prices, so you need a structure that enables forward contracting.

In a situation like the PJM pool, or even in NEPOOL or the New York Power Pool, you have a situation where you can do bilateral transactions long-term, month-ahead, day-ahead, hour-ahead, then ultimately the pool will have real-time pricing. This is the kind of structure that enables all of the market participants to hedge their risk, and that's ultimately what we're looking for in this sort of a setting.

Speaker Four

I'd like to talk about a few issues relating to the role of power marketers, what kinds of benefits they can bring to the marketplace, and some of their limitations, particularly in the context of transmission issues that need to be addressed.

Among the benefits that marketers provide is that they increase liquidity. How long does it take you, once you decide to trade, to trade at the market price? LMP gives you an option to trade at a market price very quickly. Marketers add liquidity. They make markets more efficient. They also provide price discovery, so that price better reflects value. And they provide risk management, by helping to manage cash flow uncertainty and reduce the cost of capital.

There is currently a roadblock of transmission, with several factors. One is uncertainty of transfer capability, because of low and/or questionable ATCs and arbitrary congestion management. Another problem is lack of non-discriminatory open access, with native load bias. And the lack of a true secondary market, with restricted price on resale of transmission.

The consequences of this situation include reduced transmission liquidity, making it difficult to buy, and practically impossible to sell; reduced generation liquidity; an inability to fully manage risks; and

credit/counterparty uncertainty.
What are some solutions? We need to have genuine non-discriminatory access. This means eliminating native load preferences and requiring all players to compete fairly for access. We need increased transfer capability predictability, in order to provide timely and accurate information. And we need a functional secondary transmission market that allows resale at market-based prices. We can look to gas markets as an example.

In conclusion, the current structure limits potential. It reduces liquidity, increases uncertainty, and hinders mitigation. The incomplete market exacerbates problems. Transmission must be addressed. Fully functional, non-discriminatory markets are key.

Discussion

Comment: I am thinking about how we can take a structure where we have forward markets, bid/ask going on up front, at the end the system operator running a bid-based system, with forward trading in terms of financial rights, congestion contracts—and map that into the conversation about flow gates. If, in the flow gate model, the shift factors are stable, and there are just a few flow gates that are commercially significant, then there would be little or no risk in setting up a business that doesn't involve the ISO. In the first method, people can trade point-to-point rights in a secondary market, but only those that have been defined, whereas the flow gate method is constantly re-configuring all of these things. So people could offer to sell standard transmission congestion contracts (TCCs) into the forward market. If PJM continues to do what it is doing, and if these assumptions are correct, you can set this up as a private business that does not require any institutional design change. But I do not want you to modify what PJM is doing in order to make your system work for you.

Response: The fair test would be to take on that challenge and do it. My company would set up a market, identify some flow gates in, say, PJM, allow marketers to buy TCCs, sell flow gate rights, and create a market in flow gates and trading. We can provide all of the IT functions, simple markets, etc.

Comment: What is important is that you don't then go back to PJM and say, you have to agree with us that these are the right flow gates. Because I do not think they would agree with you. We still want to set up the structure right. Then you can do all of these things. We do not modify how the system operator does things in order to validate the flow gate model. If the flow gate model is correct, we do not have to.

Response: If you leave the PJM system alone, is there an opportunity, if the real system hasn't been captured by the FTR market structure, for somebody to come in and arbitrage? I think that's just the definition of a market. If you impose a market structure that's not really based on underlying market principles, then somebody can always come in and arbitrage that market. Just because you have a brokering function doesn't mean that arbitrage is possible. It means that I'm a speculator, it means I have load to serve, it can mean a lot of other things than that the market itself is inefficient and needs to have another system imposed on it.

Question: What do you do if self-scheduled transactions don't match up with a feasible security constrained dispatch? You can administratively jigger the system, do rearranging with bid prices. The idea is that if you don't need the day-ahead market for reliability, then don't have it. But until we're very confident, we're going to have it. Do you do it with economics and bids, or do you administratively manage it?

Response: In terms of reliability, you're still going to need the models. It is a question of how far you let the models go in terms of rearranging transactions. My contention is that if you put together the flow base systems, it is easy to understand where the constraints are. If you say this constraint has 1,000 megawatts, and if the whole structure using flow base system takes care of the loop flow problem because people are reserving on the multiple flow gates they impact, then you have a simple system. The problem, whether it's the California ISO or LMP systems, is that you don't make people balance their schedules. But if you accept all schedules, the ISO or the RTO becomes a very significant participant in the energy market in order to balance transmission.

Question: PJM has tried to make sure that if you have firm service, you will be re-dispatched, whether you're serving native load or a bilateral contract. If you are non-firm, willing to buy through congestion, you will be re-dispatched. That, to me, is comparability. Yet this comparability argument keeps coming up. Why?

First Response: American Electric Power called 87 TLRs last summer, and PJM, I think, called three, and they were in a minor category. PJM seems to be managing congestion through a system that doesn't require TLRs, and AEP is managing congestion with TLRs.

Second Response: There are some situations where a native load preference does make for a comparability problem for transmission access. Some traders can't get good, firm transmission. They can't protect the generation positions they'd like to take on in all their markets. Frequently, when we are unable to get adequate firm transmission, it is because people were claiming native load exception.

Question: You spoke about liquidity, and made the point that LMP is the preferred construct there. If you define liquidity as a narrow bid/ask spread, does that change your conclusions?

Response: My definition of liquidity is the ability to buy or sell at market quickly. If you ask yourself which is a more liquid system of markets, bilateral with LMP or bilateral only, LMP pricing and bilateral markets wins. LMP gives you the option to trade at a market price quickly. If you have LMP to back up bilateral trading, it adds liquidity. Simple markets fail. Zonal markets end up in lots of uplift. Sequential markets, that is, selling ancillary services one at a time, end up in serious arbitrage opportunities that don't get fully taken care of. And requirements to bid in these markets create non-convex cost functions.

Comment: Part of market efficiency is market design. I think to say that a bilateral market or another market is better than the other doesn't necessarily say that's the most liquidity and the most efficient market available.

Response: There is more than one issue here. What we’re really talking about is a liquid market characterized by lots of market participants, being able to trade volume, having a narrow bid-offer spread, lots of bilateral transactions. That's a different question than what market structure will enable the most liquid market. If LMP allows for the most kinds of bilateral transactions, the most market participants, because they can hedge their risk better in that structure, then you can't lose by having bilateral transactions in an LMP market.

Comment: If that's a service people want, why not set up an LMP system as a separate effort, sitting on top of a control area, that accepts balanced schedules? And if people want that service, they'd choose it.

Response: That is almost nonsensical, because locational prices are calculated after the fact. PJM is dispatched today the way it was in 1970. The locational pricing signals are calculated from that dispatch, and they're just saying that, given that we dispatched it perfectly, this is the dispatch price of every bus. The LMP system is liquid. Participants have a way to hedge.

Comment: More liquid markets are better, but the real objective is an efficient market. The goal is not to abandon everything else in order to have a more liquid market.

Comment: It seems to me that information is the cornerstone of all of this. We'll soon have on our computer screens information about who last traded when and how much.

Comment: One of the things we originally looked at with LMP was the fact that you're trading financial certainty for physical certainty. And at any point in time, if you don't like the deal, get out. But if you want to stay in, you now have a portfolio of options to manage with. So, this may not be perfect, but it's evolving and we've come a long way.

Comment: Stock exchanges have always restricted trading to certain hours in the name of gaining an efficient market, which means liquidity for certain hours of the day, but not for other hours. In terms of the debates now occurring on the securities markets, we normally have had this view that it's an efficient market if the seller got the highest price available and the buyer the lowest--sort of a one-price system. If we allow trading on computers and every place else at any time of the day, we will not have a one-price system, but that's more efficient. I think we need to recognize the ultimate objective, and try to define what an efficient market is. If that requires suppressing trading at certain times in order to concentrate it in others, that's it. Liquidity is not an objective in itself, it's a tool.