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Rapporteur's Summary

Section I: Transmission Scheduling: Three Traffic Cops for One Intersection?

Trading across distances in an electric network presents a challenge for the open access, competitive market. There is a need for simplicity and commercial flexibility to allow choice and competition to flourish. At the same time, reliability must be maintained in the presence of sometimes substantial interactions across the network. In the presence of transmission constraints, the network interactions and procedures for meeting reliability requirements can have significant commercial implications. There are at least three systems in place or evolving that contribute in part to management of transmission operations: the OASIS scheduling mechanism, the NERC Security Coordinators, and the ISOs. Each system has a different underlying model of operations: the contract path for OASIS, flow-based proportional adjustments for the NERC system, and security constrained economic dispatch for at least some of the ISOs. What happens when the three rules produce different instructions for the same facility? What are the incentives created by the different models? Can the pieces fit together? How will the interaction of the rules affect the ability to use the capacity of the transmission grid?

Speaker One

The historic structure of the industry was fairly simple. Utilities had franchise areas and they were independent for a long time. When they started to interconnect, the transactions were still relatively simple. But they had to figure out how to deal with transfers across the interchange points and how that would relate to the control functions they were trying to perform. A set of NERC rules grew out of this.

The primary goal of NERC is to insure reliability--keeping the lights on now and in the future, i.e., ensuring that there is enough supply, transmission, margins to deal with unpredictable events. I've been trying to argue with NERC that there's a third kind of reliability: maintaining commercial business.

NERC now has ten regions, with four AC interconnections. The 22 Security Coordinators are relatively new on the landscape, and there are about 153 control areas. NERC establishes the rules with actions of the operating and engineering committees and the board of trustees. It also has task forces and work groups that tackle specific problems.

The current condition on the North American grid is one of fragmented transmission ownership and control. There is a contract path transmission paradigm, although there are flows throughout the network. There are problems to the extent that the real flows differ from that; a problem of significant flows on other people's systems that they aren't aware of because they don't see the schedules; and a problem with simultaneous grid support of both point-to-point transmission services and network services in that the two are allocated and managed on different models, although they're making use of the same grid. Transmission transactions have become more complex and cover longer distances. There are fairly spotty markets in secondary transmission. Three ISOs are mostly formed, 22 security coordinators are forming, three tight pools are restructuring, and several ISOs are in negotiation.

Is this parallel path flow problem really a problem? I created a uniform grid several years ago for those who wanted to exempt direct connects from all these schemes; only 50 percent of the flow is on the direct connect. There are multiple control areas and, under open access, many marketers involved. We must think about how marketers really act. The sequence is matched up a short time before the transaction actually takes place. There is a set of transmission control interactions in which the control center monitors loads, takes account of the schedules of interchange and then tells the generators what to do to make that happen. Most of the flows in the system are adjusted by adjusting the generation patterns, which differs from some other delivery paradigms.

There are two major kinds of informational components to these transactions: an energy title chain and a set of delivery arrangements. Sometimes, marketers discover that there is a loop and no need to do a delivery, and in those transactions, they get booked out. This book-out process is difficult to sell to traditional players in the business, but it makes no sense to do all the paperwork through the scheduling system when there is no physical delivery. This burden should be taken off operators and sent directly to settlement. Those transactions that do involve a physical delivery require that someone along the chain make the transmission and ancillary service arrangements, which then must be captured along with the energy requirements in a transaction schedule. The transaction schedules are given to the control areas, which turn them into interchange schedules which must be checked with neighbors.

If this is all successful, a delivery is made and goes to settlement. If it's not successful, there is some amount of interruption, and it goes to settlement as well. The problem is that the models for making the transmission reservations and the models for controlling the system are different and may give different results. If the interruptions occur only a small percentage of the time or involve a small amount of money, the simplest method is probably the best method. If there are interruptions 20 or 50 percent of the time, this is where the debate is engaged.

Many stakeholders are involved in this process. Those who are trying to sell generation into the broadest possible market often have a different point of view from those who are trying to serve load from the broadest possible supply and from those in the middle. There's also an emerging point of view from the end-use customer; NERC, at its last board meeting, voted to put two end-use customer representatives on the board. And regulators often get lost in the shuffle. The challenge is to reconcile the differing needs of the commercial requirements for transmission with the technical requirements. Neither side must be allowed to dominate the problem.

There are several types of transmission service risk, which is the risk that the grid will be unable to provide services. This can mean denial or interruption of service or the application of expensive remedies, often after the fact. These risks can be put into three categories. Operational risks are caused by weather, equipment, etcetera. These kinds of risks are best managed by the transmission provider, although today much of this risk is on the market. Market risks are those in which demands are either out of alignment with the design of the system or an unusual pattern of load or generation causes the transmission system not to be able to satisfy the demands of the market at that point. The market is in a better position to manage these risks, but they are often on the transmission provider. The third set of risks is structural, where the full capability of the system is not being used. Often this is because of disagreement about who has the rights to the transmission in cases where the model for the reservations is so far out of alignment from how the flows actually take place that the prudent transmission provider feels he has no way of managing the risk, so gives a very conservative estimate for ATC. Therefore, there is transmission at the end of the day that doesn't get used very well.

These structural risks must be minimized and the right risk management put in place. This is an evolving model. We can view transmission systems as containing three layers: the physical; the operational, which includes some planning; and the commercial, which comprises market activity. It is my view that the boundaries between these layers are the most difficult to solve because they require knowledge of both sides.

Speaker Two

With three forces pursuing a competitive market in different ways, the efforts are sometimes not synchronized and create barriers to competition. First, I'd like to address FERC's initiatives, which are, in my view, lagging behind the needs of the competitive market. Order 888 didn't go quite far enough. The utility merchant function advantages continue. The transmission system operator is still allowed to compete with power marketers for the same supplies. And there are still transmission services being provided under a variety of tariffs, resulting in a lack of comparability. Our position is that we should make a determined effort to convert customers from sales status to transmission customer status. This would be extremely effective in establishing transmission capacity rights which would give the customer more comfort in choosing an alternate supplier. It would also help to clarify stranded investment.

The transmission providers have taken the lead, participating heavily in NERC and regional reliability councils. They established tagging and the Security Coordinators. But they are implementing the fastest rather than optimal solutions.

New competitors are guinea pigs in the experiments to cure monopoly power. ISOs, I believe, are established primarily for the benefit of the transmission providers, for the utilities. This is a way on an interim basis to try to remedy market power, less painful than selling off assets. NERC’s Security Coordinators perform many of the same operational functions of an ISO, but do not embrace the other attributes necessary to have the credibility they need as part of the competitive market infrastructure. OASIS is technologically a very capable system, but the results since it has been implemented are unsatisfactory because the information is not accurate or timely. There are also new groups in the industry that are sorting out their roles.

I want to talk a bit about NERC Security Coordinator procedures versus the FERC's ISO principles. Part of the problem is that the Security Coordinators are an exclusive, self-nominated group which established its role in the industry but has taken on a lot of the responsibilities that FERC and the new competitors in the industry believe should be handled by an ISO. There is a lot of overlap between NERC's procedures document for Security Coordinators and FERC’s ISO principles issued in Order 888. NERC Security Coordinators are to execute next-day security analysis, including load flow studies, to ensure the bulk power system can be operated in a manner to support anticipated normal and contingency conditions. FERC says that an ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading. We do not believe that the Security Coordinator rules promote efficient trading.

Another contrast is that the Security Coordinator's procedures say that studies shall be conducted to highlight potential interface and other operating limits, including overloaded transmission lines and transformers, voltage and stability limits, etc. The FERC says an ISO should have the primary responsibility of ensuring short-term reliability of grid operations. Its role in this responsibility should be well-defined and comply with applicable standards set by NERC and the regional reliability council. An ISO should have control over the operation of interconnected transmission facilities within its region.

The NERC procedures say the Security

Coordinators shall share the results of their system studies within their interconnection no later than 1500 Central Time for the Eastern and Quebec interconnections and 1500 Pacific Time for the Western interconnection. FERC says an ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the commission's requirements.

Tagging is a process in which the last marketer in the chain of transactions is required to send to all parties in the chain data on all of the physical transmission transactions that occurred. This way, they know who in each wheel was responsible for the transmission service and that party can then take care of any problems. It is a valid concept with poor implementation. Transmission operators who receive the tags compete with marketers for the same supplies, because they are buying energy for their retail native load. Once they know all the transactions, they can go to the source and offer a higher price, threaten curtailment of supply or curtail the transmission service to make the supply available. Another problem is that marketers have to reveal all purchases and sales to competitors, the other power marketers, generators and load in the chain. That's not good commercial sense, and would never be done willingly.

But the real problem with the process is that most power marketer transactions require two or three wheels. A transaction can be considered firm but, by virtue of the fact that there is an economy purchase, the entire transaction is deemed to be non-firm. Thus, all of these firm transactions can be curtailed because of constraint on a parallel system. Commercially, that is not viable. It means that we can never make a firm sale unless we can convince this customer to incur the additional cost of buying firm point to point within its own system when it already has redundant capacity. The whole transaction would also be non-firm if any of the wheels is non-firm. This needs to be addressed. In addition, who is going to redispatch? Our opinion is that the parties that sold the marketer firm service have an obligation to redispatch. This is what the pro forma tariff directs.

The point is that there are three different efforts aimed at the same objective, and sometimes there is turbulence. How do we smooth out the flight? Primarily, Congress needs to authorize and fund FERC's role in the oversight of reliability for the transmission system. FERC shouldn’t displace NERC or do NERC's job, but we need the due process of an organization that can represent the interests of the entire industry. Can more industry work groups or task forces produce better results? I don't think so. The problem is groups heavily populated by the regulated entities, with scarce participation by everybody else.

We need a separate body responsible for coordinating with NERC. Every time NERC comes up with new policies or procedures, it should get the input of a competitive issues council. The council can support a process to try to arrive at some consensus on new procedures to support reliability. Likewise, any new competitive processes should be addressed by NERC for their impact on reliability. If both groups then go in agreement to FERC on an action they want to take, FERC should agree to it.

If they don't agree, FERC can address that.

Speaker Three

I would like to approach the problem from the systems operation point of view. Who's responsible for reliability, anyway? From the system operator's point of view, it is a hierarchy. First is the control area, within which you try to balance load and generation. You measure the electric system load, flow, and boundaries, and try to balance that with generation. Next in the hierarchy is the ISO. An ISO could be a control area, but doesn't have to be. Beyond that are security coordinators. All of these entities use criteria established by NERC and the regional reliability councils.

Control areas balance load and generation, and part of this function is interchange scheduling. There are many more transactions today than several years ago. With the advent of power marketing, the ability to schedule transactions has greatly increased in terms of distance and complexity. The development of this system has created some problems that NERC has been trying to address. The control area is responsible for security monitoring in its own area. However, with many transactions flowing around the system, particularly with a contract path fiction, it becomes difficult for a single entity like that to make sure the system is reliable and to take remedial action if there is a problem. So we've developed more coordinated operations across the system.

The next step up in the chain is the ISO. This involves monitoring of conditions, not just overloads in systems, but also looking at contingencies. We make sure that no single event, no single loss of a line or a generator, will cause a system disturbance or blackout. The ISO or the pool facilitates the commercial market. This is the lifeblood of the industry, and it is the ISO's job to make sure that the marketplace is coordinated so that everyone is treated in an unbiased, fair manner and that as many transactions can take place as possible. This involves day-ahead coordination of transactions and interchange schedules, as well as studies to ensure that that day-ahead schedule will produce a reliable result. To the extent that it won't, there must be methods to roll back some of that proposed business.

An ISO can be a control area, although this is not true of all the ISOs being developed. It is my opinion that a strong central dispatch is required as part of running an ISO, particularly in the presence of transmission constraints, in order to make sure that the system operator has the tools to run the transmission system within its limits. It is not possible to operate the transmission system, as some have suggested, without significant control over generation. The market can handle it to a certain extent, but not in a timely enough manner to ensure that limits are maintained and there won't be any problems.

Security coordinators are the next step up the chain. The impetus for their formation was a 1993 incident of overloads in the Midwest in which different control areas were taking different actions, which worsened the problem. The purpose of Security Coordinators is to address inter-area and inter-regional concerns. Part of this is dealing with unscheduled power flows-- often referred to as parallel flows or loop flows. These result from the contract path fiction in which the electricity doesn't flow down a straight line and along the path that's been contracted for but, instead, through the network. So a control area may experience flows resulting from a transaction for which it has no contract, is getting no compensation and perhaps in the past didn't know the source of. Methods are in the beginning stages of development and are being explored by NERC's security coordinator subcommittee. NERC has also asked the commercial practices working group to address this issue.

Tagging also resulted from this because of the need for curtailments. The system operator needs to know where the transactions are coming from and going to. Scheduling is more complicated, now taking place in two dimensions; the flow goes from control area to control area but the contract and the money may go through a whole chain of marketers and to a variety of different parties. In an emergency situation, the operator must know these details and be able to take quick action. The process of tagging and the information involved is essential. The commercial ramifications need to be addressed so that no one is unduly harmed by providing information to a system operating entity.

How does all this fit in with OASIS? Currently, OASIS is a tool to reserve transmission room. But it doesn't guarantee that a transaction will occur. Contingencies can occur, lines can go in and out of service; the pattern of flow may dramatically differ from day to day. NERC and others are studying this complicated problem, but there is much room for improvement. Control areas provide the transmission service within their open access tariffs. The ISO may or may not have its own tariff. All of this is in conformance with NERC, FERC, DOE and the standards of any other organization involved. The security coordinator handles the interregional aspects, the line loading relief required, the coordination of emergency deliveries when there are shortages of capacity, etc.

There was an allusion to the model of three cops in the same intersection. If it works as it is supposed to, it's like the NYPD Blue model where a cop in a building is in trouble and calls for backup. The ISO, the second cop, responds and helps him to take action. The third cop, the Security Coordinator, stands guard outside to direct traffic and perhaps stop the getaway car. And there is a police review board made up of NERC, FERC, DOE, and anyone else, which reviews the actions to make sure everything is handled properly.

General Discussion

Question: If the security coordinators and the ISO are the same entity, does that help solve some of the problems inherent in the competitive barriers to competition?

Response: The ISO should perform the security coordinator functions. The problem is that there are 22 Security Coordinators, which is too many ISOs. There should be three or four ISOs for the Eastern interconnect and fewer than that for the Western interconnect. To adequately and accurately assess the capacity of the transmission system, one needs to look at the big picture. In many cases, the 22 security coordinators are transmission-owning utilities which are looking at too small of an area, have self- appointed power, and have none of the standards of conduct that FERC provided for in Order 889.

Comment: The incentives for the Security Coordinators and ISOs are not to move power, but to preserve reliability. As a result, we're seeing very conservative capabilities. The process is broken. I support eliminating a lot of the OASIS requirements and tagging processes for hourly transactions.

Response: You are characterizing a structural risk, that is, the way the business has been structured keeps us from using the system to its optimum. The longer-term markets could probably deal with the OASIS process that's in place today, but the hourly market needs a more automated process.

Response: My company's problem is less with tagging than with the TLR. As far as shorter-term transactions, the problem with OASIS is pervasive non-compliance with FERC's requirement to post available transfer capability on the system. We should be able to look at the ATC and make a good assessment of whether the capacity is there to do our transaction. We should be able to schedule it directly and bypass some of the bureaucratic process.

Response: My only caution is that with electronic scheduling, care needs to be taken to ensure that the process does not become so automatic that the system operator is cut out of the loop. From the systems operation point of view, there are concerns about being able to monitor and control the amount of flow. There needs to be a balance.

Comment: The crux of the problem is which transmission provider is responsible for the parallel path. In the Midwest, we see the problem of individuality, which results in overselling. Line loading relief on a continual basis is not in the best interest of the customer or the transmission provider. We in the Midwest think that those flows must be internalized, with one transmission operator who has all the information. "Independent" is the most important thing about "ISO."

We would like to see the hourly market back to being handled by phone on the transmission side. The ATC posting in that last hour is meaningless. Instead, you would have overnight to establish the record and yet the market still can go by phone. We can't wait for another rulemaker.

Comment: I wonder whether there are a sufficient number of people who have those skills given that they are in demand and whether there is a reliability concern in the potential shortage of people available to operate the transmission system at the prices that are likely to be available within what is still a regulated framework compared to all the other opportunities that they are likely to have.

Comment: Over time, groups tend to train each other. But the commercial and operational layers are changing, and their interface is changing. We don't have enough people who understand the whole picture.

Question: Are the people who do understand it are being pulled out of the operational layer and into the commercial layer at a rate rapid enough to cause reliability worries?

Response: Yes. It's partly to do with the Chinese wall concept in which, for example, a utility will create a marketing arm and because the salaries tend to be higher there, the experienced system operator moves to the marketing arm. Another aspect is that with the multiple market participants that a system operator has to deal with, there is a need for more people in the control room. It takes a certain personality type to be a system operator, decisive and brash.

Question: What you mean by optimum and by value? Is the goal to make the contract path not fictional, but factual?

Response: The contract path works well, by and large. The connection of the historically simple commercial model to the complicated physics model that represents the real system, has started to fail in the East, though not in the West. The contract path model is not a fiction today; it is working in places.

Response: The implication to the marketer of pulling away from contract path to flow-based transaction is the elimination of competition for transmission services. Currently, individual transmission service providers are motivated to discount from time to time. We don't know that a large ISO will have that same motivation.

Question: Two dominant commercial goals would run afoul of anyone with substantial authority within that ISO—that of running a generating unit at any time during the day irrespective of its marginal cost in relation to alternative resources, and that of, as a consumer of electric energy, wanting certitude or price structure that is divorced from fluctuations of the spot market. Both can be accomplished by contracts, but the contracts are catering to the economic consequences of the use of the system and need have nothing to do with the actual operation of the system. What are the commercial goals beyond these?

Response: Power marketers are a margin-based operation, and must maximize margin by controlling risk, which requires price certainty. We need some dependability that the commercial transaction that we enter into on the electric side is going to happen as we have contracted for.

Question: How do we operate between now and the time when there is some kind of Congressional certitude as to how we should move forward?

Response: It might be helpful if legislative actions come about, but we all share the responsibility of trying to solve the problem.

Comment: There is a solution to the contract path, but people will not invest because there are no incentives in the transmission system to solve the problem. If we decide to use the contract method, industry will solve some of the problem. Alliances with the affected parties can form to come up with allocations. Then the parallel flow issue disappears.

Response: There hasn’t been research as to what a network of fax devices would be like to control. Technology will help as time goes on, but we have to be sure we're well-informed as to what we're doing. Contract paths are not the whole problem. The problem is the reconciliation between the reservations that are made and where the flows are going. Gap needs to be revisited.

Comment: The one thing I'd like to see in Gap is Commonwealth Edison’s proposal of a few years ago that any provider could make the transmission arrangement under Gap, keep the first 10 percent of the deal, and divide the other 90 percent according to the Gap algorithm. This results in a good commercial interface which retains the flow-based issues.

Question: In the New York Power Pool, what is it about control over reliability that is inappropriate to be in the hands of the ISO as opposed to having a separate reliability council as has been proposed?

Response: The intent of the reliability council approach is to provide the transmission owners, the eight utilities in New York State, with the ability to continue to influence policy with respect to reliability. It is not intended to replace the ISO in this respect. In New York, the transmission provider would be liable in case of a blackout.

Comment: I'm concerned that we may collectively set our sights too low. We all entered this enterprise because we think that the U.S. electric system can become more efficient. We don't want to settle for no harm done or for just getting back to where we were.

Response: On one hand, I would like to see standardization in the industry because it makes it easier to do business. But then we lose diversity and good ideas. We need to try to find the right balance.

Comment: I'm concerned about bidding transmission providers off against each other to get the lowest price. The ISO--at least the one in the Midwest--will have a substantial incentive to discount: It's going to affect their pay. The transmission pricing is wrong--it might be giving someone an incentive to sell someone else's system to which they have no rights. Why are we recovering fixed costs on the basis of transactions? It's a monopoly. Once the fixed cost is recovered, power should be able to move simply from marginal costs.

Comment: We should put those costs on load and be careful that we're not creating problems in terms of various commercial interests. We should be careful about trying to make the system follow the contract path because that may not be economical.

Response: As far as the idea of an access charge, there is an experiment going on in Texas that bears watching. But is that revenue requirement notion the right way to do business? Many industries plant fixed charges to produce things that they sell like transactions. They do market analysis to figure out the right balance between what they're charging and what it's going to cost them to build that product. We're lacking that kind of thinking right now.

Response: NERC is making an honest attempt to get away from the old boy's network and has developed a due process procedure. There is an honest attempt to give all transmission users and providers and everyone else a fair shake.

Comment: I am sympathetic to concerns about setting up systems which will sell us short. We see this in places like the United Kingdom, where a system has been set up that is not the best and people feel they can fix it later. But then you find that you have created vested interests and rules and constraints, and you can't fix it later. Trying to think through this problem as best we can before we get set in a system is going to be a challenge.

Section II: NUG Contracts: Whose Assets? Whose Liabilities? Who's Left Holding the Bag?

Above-market NUG contracts are a major component of the costs that are likely to be stranded as a result of restructuring. The prices set out in those contracts were established in anticipation of higher prices for electricity than the market is currently yielding. Who should be at risk for the difference between the prices set out in the contracts and the prices actually being charged in the marketplace? On the one hand, the NUGs financed their projects based on contracts that were signed and mutual obligations that were incurred. Is their reliance on those terms rooted in the sanctity of contracts that cannot be broken, or can those instruments be altered in the face of fundamental economic and institutional changes that make compliance, at a minimum, very difficult, if not impossible without significant pain? What are the symmetries in high-cost contracts? Should NUG investors have to assume risks that they had neither envisioned nor contracted for? Should utility investors assume risks for losses on NUG contracts from which the law generally allowed them only the opportunity to pass through costs and not to earn any return? Should consumers have to assume all of the risks in order not to impose them on any set of investors? What of the regulators, who, in some cases, may have blessed the contracts at the time of their consummation? Did their past or present actions put the consumers on the hook for costs that are stranded? How will they evaluate the efforts of utilities to mitigate the costs of the contracts? What constitutes a "prudent" course of action for a utility trying to rid itself and its consumers of excess costs? What types of attacks on the contracts are consistent with the law and constitute prudence from a regulatory perspective?

Speaker One

The reality of the marketplace is that there is probably no way that some utilities will recover these costs. What are the reasonable expectations? The response we got to our arguments that the NUG investors should be taking the same risks as the utility investors was that the NUG investors invested in projects based on contracts and have every right to believe that they will be fulfilled. But from the utility perspective, their investors have expectations that are equally solid. So, you have to ask whether these expectations are iron-clad.

There is an analogy to the Natural Gas Policy Act. When it was enacted, the Kansas legislature passed a law that overrode the price terms of gas contracts that would give the gas company unfair price advantages or price increases that would result in monopoly or windfall profits. When litigation went to the Supreme Court in 1983, the Court said that the state can adjust the rights and responsibilities of contracted parties where the state has a significant and legitimate public purpose for doing so and the adjustment is based upon reasonable conditions. The state interests that the Court saw as legitimate were the elimination of unforeseen windfall profits and hardship on consumers with fixed incomes. The Court said it was significant that the parties were operating in a heavily regulated industry, so that even though, at the time, the state did not regulate these prices, the parties came into the arena knowing there could be regulation in the future.

In the early stages of PURPA implementation, there were signs from the courts and from FERC that this was not necessarily a permanent arrangement. There was a lot said about supporting the formation of contracts, but FERC never promised a regulation-free environment. The Supreme Court, in the case involving the utility industry's challenge to PURPA, said that the full-avoided-cost rule is subject to revision as FERC obtains experience with the effects of the rule, and that it may be in the interests of a qualifying facility to negotiate a long-term contract at a lower rate.

Question: What about the effect of Windstar? It seems to cut both ways in terms of sanctity of contract on one hand, but protecting the utility for recovery of these costs when the government changes its mind.

Response: Windstar strongly suggests that the government cannot change the rules to the disadvantage of those who make investments and rely on them. What this suggests is that the problem is now the government's, not the investor's.

Speaker Two

The issue here is not just Independent Power Producer (IPP) contracts, but the disparity between wholesale and retail rates. Rather than looking at IPP costs in isolation, we need to look at all efforts possible to reduce retail rates. Other impacts include securitization of stranded costs, efforts to restructure and open up the markets for retail competition, performance-based regulation measures to increase the efficiency of existing utilities, proposals to close inefficient nuclear plants, and mergers and consolidations of inefficient utilities.

Historically, Qualifying Facilities (QF) developers entered into binding long-term contracts with utilities. Developers entered into similarly binding contracts. It is unrealistic to think that these agreements would have been made if developers thought power rates would be challenged. Any impact on the contracts will have a ripple effect on other contracts.

Current problems are unanticipated. Avoided cost estimates appear to be wrong. There is pressure on utilities to reduce rates. Hardball "Mug-a-NUG" efforts have failed; they have created a turf war in which the market participants have dug in their heels and hired scores of lawyers to try to raise any possible contractual, regulatory, legal, or other argument that they can think of in order to change the posture of the parties. This is not just a contractual issue, but has its roots in PURPA, so to treat it like any other contract is a mistake. It is ignoring important pre-emption arguments that have been successful in the Freehold case as well as in other cases in other forums. FERC has refused to seek to modify existing contracts, and there are no serious legislative proposals before Congress that would modify the existing power purchase agreements.

As a policy matter, why shouldn't we try to undo these contracts? The industry is moving toward a competitive marketplace. The basis for the new marketplace is the existence and upholding of power contracts, and to start this new marketplace with an abrogation of substantial existing contracts will have a chilling effect on the development of this new market. Other contracts would be impacted substantially if power purchase agreements were altered--there are third-party contracts with steam suppliers, lenders and fuel suppliers. There could be employment effects, productivity effects, effects on the ability of an industry to continue operating in a market that brings up questions of elasticity of demand and whether that industry would seek to relocate. There are lender considerations.

The most successful attempts to alter the existing power purchase agreements have been through renegotiation. Through March 1997, utilities are reported to have bought out 174 IPP contracts totaling over 7000 megawatts. That includes the ongoing contractual negotiations between Niagara Mohawk and 29 IPPs. Negotiated resolution increases in the pace of competition, to the benefit of ratepayers.

There are three models for the renegotiation and restructuring of contracts. The Niagara Mohawk model was really a set of negotiations among Niagara Mohawk, the various independent power producers and state officials, including Public Service Commission officials and officials from the Governor's office. Lenders were brought in from time to time as well. This agreement would then be subject to the approval of the various third parties. The California model is a different approach, with negotiations among all industry participants and recovery through a Competitive Transition Charge. And there are many individual utility and IPP negotiations that take place one at a time. The successful cases are the ones that have taken an approach similar to that of Niagara Mohawk—sitting down and having a global plan to try to breach the gap. In order to renegotiate a power purchase agreement, you must obtain approvals from the interconnecting and transmitting utilities, thermal hosts and site landlords, fuel suppliers and transporters, operator of the facility, and the various financial entities that are providing financing for the facility.

The most important thing to realize is

that it's not going to be easy to get out of these contracts, and most of these contracts are not going to be abrogated. The continued efforts to play hardball, to fight through litigation, will delay the savings and benefits that will result in competition. What is occurring in New Hampshire, where restructuring has been suspended, is a perfect example. The consensual restructuring and renegotiation of these contracts is the best mitigation.

Speaker Three

If renegotiation of these contracts is in the societal interest, what rules should state regulators or legislatures apply in looking at the question of recovery for non-mitigatable stranded costs? I would like to discuss the issue of whether utility management would be wise to commence a suit for declaratory judgment in a state court that the contract should not be abrogated, but should be the subject of a doctrine of excusable non-performance. We should examine what the predicates of that litigation might look like before we conclude that we can simply have consumers pay these costs.

Freehold was a 1990 decision of the U.S. Court of Appeals for the Third Circuit which dealt with an effort by the New Jersey Public Service Commission to force renegotiation of these contracts. The plaintiffs brought suit claiming that this offended the Supremacy Clause, and the court agreed that there was pre-emption of state authority by the commission. In doing so, the court stated that its task was to examine not the merits underlying the controversy over whether the PPA executed in 1993 could now be revised or altered, but only whether PURPA preempted the order directing the parties to renegotiate. It concluded that it did. So the state utility commission, and perhaps the legislature, is precluded.

But does that mean that Freehold declared the sanctity of these contracts? No, as the court said that it wasn't speaking to that issue. We have built our commercial economy on the understanding that contracts are parsed into two different schemas. One is a contract for an individual transaction; distinct from this is a contract which founds what is expected to be a long-term relationship between the parties. The second type of contract cannot anticipate every variable that will occur as the relationship is lived out, so the parties must constantly be prepared to revisit the purpose of the relationship and to adjust the terms under the influence of what was perceived to be its purpose. This is useful to keep in mind in looking at the current circumstances of the electric utility industry.

The Trans-Atlantic opinion, written by Skelly Wright, framed the modern doctrine of excusable non-performance. Wright wrote that a thing is impossible when it is not practicable, and that a thing is

impracticable when it can only be done at an excessive or unreasonable cost. When this issue is raised, a court is asked to construct a condition of performance based on changed circumstances, which involves at least three steps. First, a contingency, something unexpected, must have occurred. Second, the risk of the unexpected occurrence must not have been allocated either by agreement or custom, and third, the occurrence of the contingency must have rendered performance commercially impractical.
Excusable non-performance has been allowed in American jurisprudence since at least the 1780s in the doctrine of impossibility. More recently, the emphasis has been shifted to impracticability. There are at least two other doctrines that can be examined in appropriate circumstances: frustration of purpose and failure of mutually presupposed suppositions. Both are made up of two essential ingredients, a physical or economic impact and foreseeability.

Our initial jurisprudence concentrated on physical barriers to performance, that is, impossibility. But now we look much more to the question of whether it costs too much of society's scarce goods and resources to pursue the objective of the contract--the claim of commercial impracticability. Physical impossibility is off the table here since no utility claims that it is physically impossible to carry out the terms of a power purchase contract, but the doctrine that it now costs too much to do it bears closer examination. And the doctrine of frustration of purpose may be the most apt. Frustration of purpose admits that the contract as originally framed cannot be performed, asserting that the value of the performance from the other party has, because of unanticipated and after-arising circumstances, lost its utility.

There was a recent decision in an interesting context, called Alcoa, in which Alcoa entered into a contract under which it was to fabricate alumina for a firm called Essex into bars of aluminum. Essex would take the refined aluminum and extrude it into wire for electrical purposes. The contract was to exist for ten years with an option to renew for five, and since the parties recognized that they couldn't tell exactly what Alcoa's cost of performance would be over that period, they put in an escalator clause which was the general CPI. Alcoa found after five years that while the CPI was tracking gross inflation because of dramatic increases in the cost of electricity which it needed to utilize in order to smelt the aluminum, its actual costs were going up at a rate which bore no sensible relationship to the general CPI. Alcoa sued for a declaratory judgement that the pricing mechanism that the parties had agreed to, given after-arising events, no longer made commercial sense. The court agreed. It is interesting to note that the Freehold-deciding Third Circuit Court of Appeals has characterized Alcoa as an excellent modern application of the doctrine of excusable non-performance.

Speaker Four

The decision in American Electric Power was a unanimous decision of the Supreme Court upholding the full-avoided-cost rate as both the maximum and minimum rate required under PURPA. The states are very different in terms of how they calculate capacity prices and when they are available. Price can be taken on an ongoing basis or QFs can take the forecasted price at the time the obligation is incurred. Almost all have elected the latter option, which is dictated by the market and which is where the current debate originates, because the forecasts have proved largely optimistic. FERC has clearly indicated that it expects the forecast price to diverge from the actual/avoided cost at a given time. This tempers some of the available remedies.

Can you remake the QF price unilaterally on behalf of the utility? Utilities have been uniformly unsuccessful in taking this frontal approach. The legislative history is fairly clear that when the states act, they are acting as delegates of the federal government; there is no independent state authority to work the QF price. The court decisions, Freehold in the Third Circuit and one in the Ninth Circuit, don't give great encouragement to this kind of attack on the QF price. There is language in Order 888 suggesting that QF contracts must be honored, as well as approximately six FERC opinions uniformly holding that authority is exclusively federal and that there is no retroactive application once the contract is made and the appeal period is passed. There are at least five states that have looked at this issue, and utilities lost in all five.

I believe these QF contracts are in some jeopardy. Several techniques imperil them. One is the bankruptcy option, used increasingly in reorganization as a political tool for purposes of redoing labor contracts, environmental obligations, or liability and for renegotiating contracts. It is unclear how the federal authority of the bankruptcy judge would relate to PURPA authority.

In addition, there are a number of contract defenses that have different prospects for success. These defenses are difficult to win on. They involve state courts interpreting state law as to whether any of these defenses work as a matter of contract law, yet overarching all of this is a federal regulatory responsibility placed on utilities. These contracts are susceptible to an interpretation that they were designed to be fixed-price contracts and the risk was allocated with divergence in prices expected. It is also a bit politically difficult for a utility to assert some of these defenses if it has stranded costs due not only to deregulation but also to overbuilding.

In looking at QFs in certain systems, I

have found up to half not complying with contracts. If there is a violation of the existing contract, there is nothing to preclude an enforcement action reaching retroactively into the past. If this is interpreted as a matter of contract as opposed to a regulatory requirement that supersedes the contract, it depends on the statute of limitations in a particular state. If one is successful in arguing that QF status has been lost because it no longer qualifies as a co-generator or a small power producer, FERC could impose a cost-based rate, perhaps retroactively, for a significant period of time. There are also QF contracts with price ratchets where, when these conditions are not met, the price drops dramatically. Again, aggressive enforcement offers some possibilities.

There is a question as to whether deregulation imperils QF contracts. To the degree that a utility sells its generating assets but holds onto its purchase power obligations, that is likely a very undercapitalized entity holding just purchase power obligations and very few assets. PURPA itself is silent on whether you can assign the contracts. Whether it is legal to assign them to the buyers of the generating assets is governed by both the implied intent of PURPA and the specific QF contracts, some of which allow assignment, some of which do not, and some of which are silent. Ultimately, if some of these generating assets end up in the hands of private parties, those private parties cannot be regulated by PURPA.

What most imperils these QF contracts on an ongoing basis is the issue of curtailment of the QF purchase obligation. There is one sentence buried in FERC's QF regulations that says that the utility need not buy the power when the power would be more costly to the utility than the utility generating the power itself. The legislative history and preamble indicate that this is for situations where the utility has to curtail or ramp down some of its own planned base load or intermediate load generation to make room for the QF power. This is a reality that many utilities are experiencing today.

There are two basic types of pricing: the split contract price, where there is one price for capacity and another price for energy, and contracts paid on a kwh basis. The rules are changing as to who gets dispatched and what the protocol will be. There are three basic interpretations as to when you could back down QF power. One would be to argue that any time your marginal costs are less as a utility, you can refuse to purchase the QF power. That's unlikely to be a successful interpretation. A second interpretation would be that any time you have to ramp down a principally base-loaded plant, that occasions so-called negative avoided cost which would allow you not to buy the QF power or to pay zero for it. And a third alternative would be when you have to substitute intermediate for peaking generation at greater cost for what normally would be filled by your own baseload plant because of the slowness of its response back to meet that peak. That clearly is a negative avoided cost.

Normally, utilities will account for additional fuel, chemicals or auxiliary power needed when they ramp down large power plants. But that is only the tip of the iceberg of the true cost to a utility of having to cycle its baseload or intermediate load generation to make room for QF power. There are also additional capital costs and early replacement costs associated with metal fatigue and a creep in the tubes. These costs are huge and typically not accounted for in utility accounting of the marginal costs of cycling these facilities. There is data being developed that indicates that every time a plant is pulled back, there is an increase that shows up anywhere from one to seven years down the road in substantially greater maintenance expenses, early retirement, lower heat rates, etc.

There are a few other techniques that various states are suggesting as ways to get at QFs, which have varying degrees of legality. Some states are attempting to take zoning exemptions away from QFs that do not give up their above-market prices for QF power. This is not likely to survive legal challenge. Some states are attempting to prohibit the ability of the QF or its affiliates to engage in any kind of retail sale. Again, there may be legal difficulty in terms of due process. Gross receipts and excise taxes are being proposed in many jurisdictions to more aggressively tax certain QFs. And there are a number of mutual agreement strategies, from buydowns to buyouts, that can settle these kinds of disputes.

General Discussion

Question: What are the obligations when a contract is assigned to a private party? What if it is assigned to an EWG? Does it still keep its utility classification as far as the QF contract?

Comment: The QFs which are fearful of the assignment issue take the position that they are in jeopardy whenever the franchise utility signs the contract. So EWG by its very nature is designed to be distinct from the traditional regulated utility. If there is potential jeopardy, I assume it would attach to that kind of assignment as well as for an assignment to some other kind of entity.

Response: We are really talking about a delegation. The general common law on delegation is that it is a unilateral privilege that can be pursued at any time except when it would imperil rights which the nonconsenting other party to the contract had under the original agreement.

Comment: The question would be whether the new owner, the EWG, is less secure in some objective way. Does it imperil the security of the QF?

Response: If the original party had an

obligation to pay and the new one has none, that is not difficult to answer.

Question: These contracts are with a corporate entity which is a utility, many of which are selling off their generation for one reason or another. Can you put the corporate entity into bankruptcy?

Response: It is interesting that many state commissions may sanction the division of utilities into somewhat separate entities and the Genco may be left holding the utility assets. When it at some point sells those, it will be left largely with those purchase power and purchase sale contracts. What's to keep that entity in ten years, if it gets in trouble on the contracts, from taking the rights that federal law provides?

You would want to consider strategically, when a corporate reorganization creates a holding company and you functionally unbundle the previously vertically integrated utility, whether or not you can successfully transfer the liability under a contract, as opposed to the performance of its duties and the liability to pay the other party. This is the distinction between an assignment and a delegation, and it is not clear that you would succeed in evading the liability of the holding company. If you go through a bankruptcy proceeding, there would also be the question of whether or not you could seek enterprise reorganization to hold the greater corporate family liable for the sibling's debts. The greatest chance of that being successful is if the sibling was saddled with debts of the previously now-separated corporate entity.

Question: In discussing the defense of frustration of purpose, does this mean common purpose of the sort that is usually found in a contract? How would you cast a frustration of common purpose?

Response: Frustration of purpose is normally applied when the parties don't clearly stipulate the ejection buttons out of the contract. Frustration is a very difficult doctrine to win on. It was tried unsuccessfully in some of the gas deregulation cases. In this case, the one situation where it could possibly work is where the contract does not smack of a fixed price, where there is language that this is meant to be a reflective proxy of system fuel costs, a regional fuel basket, or something of that nature.

Comment: Utilities have applied to public service commissions to do away with the cost recovery mechanism, with the concern that a utility may now want to use a regulatory out clause to say it can't recover the cost associated with the power purchase agreement and therefore can get out of the contract.

Response: I have never heard of a case of excusable non-performance being successful where there was any evidence that the party seeking it was at all responsible for the circumstances, and certainly not where that party could be shown to have actively inter-meddled. These economically unrealistic contracts should be renegotiated, and the question is how to assist in this process. Arrangements which are grotesquely out of whack with economic reality cannot be seen as binding obligations.

Comment: It is not clear under what circumstances curtailment would be permitted. In FERC’s regulations and preamble, the circumstances are limited to operational circumstances of the utility. And they are intended to not abrogate or undo the existing contractual obligations. Where a utility says it should be permitted to curtail because there is a difference between the QF price and the marginal energy cost, FERC's preamble answers this in the negative but leaves open the issue of what constitutes the type of limited operational circumstances that would be required in order to come to this negative avoided-cost concept.

Question: The fact remains that someone has to pay these costs. It is unfair to say that it should all be eaten by the shareholders. Are we in a prisoner's dilemma situation where both sides hold out for everything, and everyone loses?

Response: The basic problem with the legal system is that the only parties whose rights or liabilities are adjudicated are the plaintiff and defendant. The consequences visited on people and the community are not addressed. Judges Skelly Wright and Irving Goldberg have taken a much broader view.

Comment: In terms of the legal cases, it is not apt for the NUGs to say that they must be elevated to a higher status than utilities because their contracts are sacrosanct. There are all kinds of reasons why parties do not expect their contracts to be inviolate.

Question: Suppose a utility decides to divest its assets, including its net contracts, in part by offering support payments to the buyer. In that situation, is the purchaser of those assets and contracts in a better negotiating position vis-a-vis the NUGs to change the contracts to make them more market-responsive? If so, the value of those NUG contracts is higher to the buyer than it was to the utility that originally had the contracts, and the ratepayers in that jurisdiction get an additional benefit of the divestiture.

Response: NUGs were very concerned about the risk that we might assign contracts in the context of our divestiture and that some of the parties acquiring those assets might have more political muscle, bigger war chests, etc. Even if this is more perception than reality, it is still important, though I am not sure what the real value would be.

Question: If the courts don't pay any attention to the third parties, where does legislation like that of

Massachusetts come in, where the argument is being made that state legislative action will be challenged by the IPPs? Does this bring a public policy question into the courts?

Response: To the extent that whatever the challenge is is not a slam dunk case, yes, I think it does. There is a capacity of judges to take into account interests which are not vocally before them in making decisions. This is an unexplored area.

Comment: There was an assumption earlier about securitization, but politically, it is not a slam dunk. So you can't go into a NUG contract assuming a utility is going to be able to get securitization on stranded costs.

Response: It is true that there are no guarantees, and securitization would require substantial efforts on the part of state regulators and legislators alike. If the stakes are big enough and it looks like restructuring substantial numbers of non-utility contracts would otherwise fall by the wayside, the pressure would be great to get it done.

Question: Most, if not all of these contracts, are enforceable. Enforceability and performance of contracts are mostly novel theories that have not worked in the energy sector. So we have to go beyond enforceability to talk about damages and risk. Did any party, in contemplation of retail access, allocate the risk in those contracts? The answer is clearly no. So who should pay the damages?

Response: The earlier cases are of questionable precedential value. These intentions were framed in an era so unlike the current one that the question of the utility or the QF losing because they consciously took the risk is not one that I predict the courts are going to arrive at. It wouldn't be fair. The best thing the legal system can do is to say that there is this unresolved issue that carries with it elements of risk to anybody who thinks they can maintain the status quo by collecting a huge pot of damages or by getting a decree that it will go forward even with all of the burdens.

Response: These strategies are likely to press a negotiated settlement. The curtailment strategy has been successful in some places recently. The difficulty ultimately is whether the parties were attempting to make a fixed price contract or to index something. Many of these QF contracts are driven by indices. You can argue when an index fails that it was the intention impliedly for the parties to find a substitute index that does the same thing, or that the intention of the parties was that the contract cease at the point where the index fails, at which point you renegotiate today's avoided cost. So a number of legal issues are going to result in negotiations that will drive the policy issues.

Response: In addition to the salutary effect of instituting a declaratory judgement action on motivating the parties to work some of these difficulties out themselves, FERC could usefully overturn the Freehold doctrine by saying that it is relieving the states from preemption to the extent that they are trying to work out the stranded cost issues with NUG contracts. Then there would be a rush of people eager to find ways to avoid putting this to lengthy adjudication. Still, the ultimate issue is that, in order for the regulators to credibly advance a policy of establishing equity, they have to define the endpoint that they will seek. What we would want is a standard that would be defensible and that would force renegotiation or produce an adjudicated result with some coherence. The result is not going to be very equitable because the contracts are so diverse in the ways that the money has been taken out of them or in the ways they have been financed.

Comment: With many successful renegotiations of these QF contracts, regulators premise approval of the renegotiations on ratepayer savings associated with the buyout and the buydown. These were done based on valuations over the future price of energy and capacity, not in contemplation of the larger valuation of the future prices of energy and capacity. In most states, there is universal disagreement as to how to value stranded cost. So it will be much more difficult to renegotiate in the future.

Response: I think actions for declaratory relief based on some type of contract defense, like commercial impracticability or frustration of purpose, would merely cause the parties to dig in their heels and litigate.

Comment: When I was doing legal research on a case in which the ratepayers were getting a very bad deal, I was looking at contract abrogation and thinking that this was a case where the legislature could step in. Then someone pointed out that none of this mattered because the shareholders of this company were primarily retired Indiana teachers fund pension funds, and there was no way we could choose between the legitimately disappointed ratepayer and the legitimately disappointed retired teacher shareholder. A case like this makes legislating impossible, so I think the only way to do this is negotiation.

Comment: Where are we heading in the future in terms of QFs and IPPs being a viable alternative? We've put this whole industry in jeopardy as far as being a viable competitor. And with the mergers of others, it seems like we're marching toward a re-creation of the 1920s, with the mega-utility being the real competitor.

Comment: Suits for declaratory judgement are brought before an equity court, which can fashion any decree which is fair, just and reasonable. Thus, it could wind up as a suit for equitable modification of the contract, not an attempt to abrogate the contract. This is one of the real dangers to anybody who becomes a complainant in an equity proceeding. Equity courts can look to impacts upon third parties.

Section 3: Electricity Policy Issues: The Unanswered Questions

Electricity restructuring has opened a range of new policy issues and problems. The future of the distribution utility and the approach to unbundled retail services touches on many concerns that raise competitive and regulatory questions. Environmental problems will continue to play a major role in industry development, and the policies on global warming that flow from Kyoto could have major implications for the evolution of the competitive market. The respective roles of federal and state regulators are still not defined. The current press of activity to define the institutions of the competitive wholesale market is not over, but many decisions have been made and entirely new structures are in place or will come on line in the coming months. Inevitably, some mechanisms will work better than others, but the lesson from other countries is that it will not be easy to make changes or even agree on the diagnoses of the symptoms. One challenge is to define means for evaluating performance and adopting mid-course corrections. These illustrative topics should be expanded and sharpened to establish a research agenda for the future. This session will focus on formulating the questions that will guide the future activities of the Harvard Electricity Policy Group.

Speaker One

I would like to discuss four areas: the issues that arise as we begin to unbundle more concretely; technology pre-eminence; regulatory reform; and environmental issues.

On the unbundling of the industry, I wonder whether or not we are setting up a system that will afford us the proper incentives for efficient investment in areas at the intersections of functions. One issue is what to do with fax and other technologies that enable you to control the transmission system and facilities in ways that often provide energy benefits--different voltage support, ability to move capacity from one side of a transmission interface to another. These could be highly attractive to investors if market rates of return could be obtained for them, but may not be as attractive with regulated rates of return because of the gray area between whether they are providing generation or transmission functions. This issue also arises in distributed generation, where some want distribution companies to do only distribution, and others talk in terms of multiple functions.

The second question has to do with technology R&D. We are in this happy situation of having many choices as a result of many decades of research in technologies that have spun into this industry. But we are now in a time where there is less support for funding many of the types of R&D of the past. And the collaborative research we have seen in organizations like EPRI is changing. There is enormous disagreement as to whether this is an issue at all. Does this matter? Is the market going to take care of this problem? If not, how can we get consensus on working on the gaps in the system?

The most controversial issue from my point of view is, can state regulators let go of some of the areas they have regulated in the past? There is a culture clash between the hoped-for competitive generation market and what we expect from regulator tools. Every state still has a requirement that somebody be the provider of last resort. This skews the market. Can we set up a paradigm in which we eventually let this market behave like other markets?

The final area is environmental policy. What is interesting is the intersection of environmental regulation and competitive markets. We have completely different roles and systems of law for federal and state policy and for economic and environmental regulation, causing tension. In this country, we start with a presumption that every new power plant or manufacturing facility makes the environment worse, to the point of increasingly high marginal costs of compliance for newcomers. From an economic point of view, this acts as a barrier to entry. On the other hand, in environmental regulation we have had successes with some of the cap-and-trading programs, such as the SO2 program. The thorny issues are to do with the allocation of allowances is doled out in the beginning. And while the movement is toward cap-and-trading programs where appropriate, we still have a media by media, pollutant by pollutant approach.

Contrast those facts with some elements of economic regulation. We share a common expectation that generation markets should be competitive and that we can get efficient outcomes. Basic economic principles tell us that we should reduce barriers to entry to make sure there are many buyers and sellers, keep externalities in mind, and prefer non-discriminatory rules. But in the environmental context, there clearly are different requirements for new entrants and those located in non-attainment areas. Some are appropriate and some of them may not be appropriate.

We have a longstanding understanding that the electric industry is a major contributor to pollution and that very different economics control the emissions from different kinds of plants. The new technologies in the industry are increasingly advantageous from both an economic efficiency and an environmental point of view. Both old and new regulatory tools for improving market performance are problematic. Most obviously, least- cost planning will not work consistently with a competitive generation market. New tools include portfolio standards, disclosure rules, renewables funds, green pricing, and generation performance standards. All of these have some problems.

One that I like is the generation performance standard, a cap-and-trade program in which you figure out how much emission can occur in a region, allocate the allowances based on a ton per kilowatt hour basis, and divide the cap by the expected generation in the region and you allocate. Parties receive the average amount of emissions allowed; those who are under can sell, and those who are over must buy or do something else to comply. Two states to date have dealt with generation performance standards as a condition of retail sales. The seller of power in a market is assigned generation performance standards, and its blend of kilowatt hour sales has to meet this pound per megawatt hour standard. That is a very awkward way to implement such a generation performance standard. A clean way to do it is to assign it to facilities, since they are the ones producing.

Tagging emissions from source to state across so many transactions is problematic technically gets at the generation performance standard in an awkward way because states are looking at the only kind of hook they have, which is retail sales.

So we find ourselves with new tools on the horizon, but they are awkward because we are still working within the current paradigm of environmental economic policy. The questions are, what can we do practically so that market players face comparable emissions standards? There are costs associated with efficiency and fairness of market rules, and if there are problems with the way the situation is currently set up, what can we do practically? Different committees have jurisdiction over the environment and over electricity commerce. Do we just assume that we can't talk about both together? We need to think about how to align economic and environmental regulatory policies in a way that encourages efficient markets and cost-effective environmental performance.

Speaker Two

I want to make three key points in my discussion of retail. The first is simply that wholesale competition is not enough; we need to foster retail competition, because only then will the maximum benefits come to consumers. n. The second point is the role of the utilities. Utilities in the retail environment should be non-discriminatory service providers. The third point is that unbundling some of the functions of the distribution company is going to be necessary to get retail competition to its maximum level. I will go over these points in a little more depth.

I believe that wholesale competition is not enough. We expect that as we create ISOs and make generation a fully competitive function, we are going to see significant efficiencies over the past approach of central planning and monopoly ownership of generation. But are we going to capture all of the benefits of competition? I think not. The reason is that every consumer at the end of the wires is unique. We all have different energy use profiles which are dependent on the hardware we have in our residences or our businesses, our habits regarding electricity consumption, the size of our family, the number of children, who works, the hours of our business, the type of clientele we have. The regulated utility is a poor vehicle for serving individual profiles. The competitive market will bring innovation in products and services that will maximize individual benefits.

The second point, if you agree with the first point, is the question of the utility's role. The utility, by definition, is a non-discriminatory service provider. That means that the utility has to treat all participants in the market equally. The utility's obligation to serve should be an obligation to provide customers and retailers access to each other, not to provide preferences. I have heard recently about underserved communities, but there really are none in a gas and electric utility situation, since you provide the same access to every customer.

Should there be a default provider? In California, there will be a wholesale price mechanism that is a default option for the customer. A point that will require future debate is whether customers should be required to select a provider, and whether that default provider role is a transitional role for utilities. I don't believe regulators want to, or should, regulate competition. The role of the regulators is to ensure that affiliate companies set up to be unregulated non-monopoly companies do not get preferences or cross-subsidies from the utility, and to regulate the interaction between the utility and its affiliate. Regulating the affiliate as it enters the competitive retail market is not a proper role.

The third point is that in order to foster the retail market and to get retail competition to its fullest level, we need to unbundle some of the functions of the distribution company. Unbundling will facilitate the contact between retailers and customers that will be so necessary in bringing customers to the competitive products.

There are potential tools in the revenue cycle that retailers need in order to effectively penetrate the market. The revenue collection cycle can start from planning for meter sets to setting meters to reading them, billing as a result, analyzing credit, dealing with uncollectables, collecting the bills, processing the bills and giving customers information about their energy use. We in California are unbundling and are having a helpful debate about what the price should be and about what the credit should be to a party that takes over those services. There is a concern that this is a new area of stranded costs, but I think it is a very manageable issue.

The revenue cycle in the context of a utility company is a fairly small piece of everything being done. There are more than 2000 utilities in this country. If each of those utilities has revenue cycle functions, they are being offered to the market in a very inefficient fashion. This is an area that is ripe for consolidation on a much broader basis than utility to utility. I believe companies will arise in an unregulated manner to offer billing and collections services.

What is the importance of this customer contact? The last thing a retail marketer wants is for its charges to the customer to show up on a utility bill with a utility logo. Brand identity is going to be very important in trying to capture the market in the future, and you don't get much brand identity if you're a line item on someone else's bill. So there is going to be a great desire to gather these services and to make them specific to the competitive retail providers that are serving customers.

The unbundling should begin promptly. The consequences if you wait to see how others do it is that someone else will likely design the program for you. I don't expect pre-emption of state action in federal legislation, but it is predictable that federal legislators will want a deadline for state action.

Speaker Three

I want to focus on four questions that are largely unexplored by people thinking about these issues. One set of issues is that if we don't get things right now, we can fix them later. The second is utility tax questions. Increasingly around the country, as you look at the fate of utility reform efforts in the various state legislatures, these efforts are stalling. This is due in no small measure to the fact that the legislatures are finding it very difficult to deal not only with the complexities of the electricity industry, but with the even greater complexities related to utility tax issues. The third issue is the array of regulatory institutions. We frequently talk about this as a federal-state issue, but it is more complicated than that, going to how the substantive activities relate to one another at various levels of regulation. The fourth question is, what remains to be regulated and how do we do it? Put in different terms, how do equity and efficiency continue to relate to the regime of providing electricity to consumers?

On the first question, if we don't get it right now we can fix it later, we must start with a couple of assumptions. One, whatever we do now in terms of changing institutions, we will not do right. We will make mistakes. The question is, how close to being right do we need to try to be at the beginning? A corollary to that of equal importance is, how easy is it to change things once they're in place?

In England, the reformers operated on the assumption that they could always fix things later. But they discovered that, despite their best intentions, this is not so easy to do, for a variety of reasons. Institutions tend to be conservative, and don't change quickly. Vested interests learn very quickly how to play the system, and they're not very interested in changes that make it more difficult for them to operate as effectively or as profitably as they might have in the old regime. There is a lot of resistance at the regulatory level, and at the industry level, to changing those things that are critical, as the actors see it, to the way they do business.

In the Freehold case, one of the understandings at the beginning was that New Jersey DPU would retain jurisdiction over these contracts. But when that issue got to the courts, at least one side, if not all the sides, forgot that, and the court never knew it. So the impact of judicial review throws another serious question into our ability to change things later.

There is also the classic Ohio Power case, where the clear understanding was that there would be reviews of the transactions between affiliated companies and registered holding companies. The D.C. Circuit Court of Appeals said no, we don't need to do that. A deal's a deal and it can't be changed, and even though it's never been reviewed, there's no ability of the appropriate regulators to review it.

So, what you find is that changing things later is not so easy. One of the questions that requires considerable exploration is, how do we leave open the possibility of changing things as we find imperfections? How do we overcome the inherent resistance of the vested interests? How do we build some dynamism into the new regime?

The utility tax questions are politically extraordinarily difficult. Legislators have been able to raise revenue through hidden taxes on utilities, while railing at the utilities for raising their rates. But it will be difficult for this to continue in the new regime, since the utilities are not so hidden and competitors are coming in with different tax schemes, sometimes with much less or no tax liabilities. Taxes from utilities are a major source of revenue for state and local governments and of education funding. How do we move from a regime of hidden taxes on utilities to taxes that are more visible, whether they're consumption- or property-based? How do we put them on the same playing field as their competitors, from a taxation perspective? These issues need to be explored both from the political standpoint and from the standpoint of the relative economics of different regimes of taxation.

The third area is the question of regulatory institutions. The current regime is going to have difficulty surviving in the new world. When the utilities or transmission owners find that the demands placed on them by the wholesale market and by their transmission-only customers are such that they need to enhance or revise the system, a common response is to ask the state commission to increase tariffs, reduce the level of reliability, or offer an interruptible or emergency tariff. This is going to be much more difficult in the new world because it doesn’t send the right price signal and is unfair. And it creates perverse incentives in terms of siting new facilities.

But there is nothing to replace the current regime. We dump all the charges on the monopoly customer and offset their obligations if we make up some of the revenues. The flip side is the question of what rights the retail bearers of the residual revenue responsibility receive in return for having borne that responsibility. The irony is that the bearers of the residual revenue responsibility may not only get an increased economic burden, but they may get less reliable and effective service. Part of the reason this problem has evolved is that neither the federal nor state regulators have thought about transmission from a holistic perspective; one thinks about it on the margin and the other thinks about it as being part of bundled retail rates. That regime requires considerable exploration.

The second aspect of the federal-state regulatory problem is that both FERC and the states have favored an approach of dividing the physical assets. But there is no great physical line. Maybe we need to think about moving away from determining jurisdiction along the lines of physical assets and start thinking in terms of subject areas and a series of agreements and understandings about how certain things get done. One area that is ripe for this kind of thinking is transmission pricing, which cannot be looked at independent of siting. Another is stranded assets and benefits determinations. Rather than dividing up the physical assets between the state and federal jurisdictions its, it may be more useful to explore the desired policy results and how to accomplish them without wreaking economic havoc or causing endless arguments about boundaries. This applies to questions about alleviating bottlenecks, which relates to trying to change the criteria for siting facilities. This relates to both transmission and generation.

The fourth area is the question of what needs to be regulated and how it gets done. The electricity market has never been solely designed to achieve economic efficiency, and that is not its only goal. How do we deal with issues like the environment and low-income programs? No matter how competitive the market is, there are going to be people who cannot afford to pay their full electric bill. Saying that the legislature or Congress should deal with this doesn't make sense politically. There are certain results that, as a matter of social policy, we are not willing to tolerate. How do we decide what results we want the market to decide and what results we find intolerable for society for the markets to decide because we don't want to live with the results?

There is a whole other series of questions about what needs to be regulated. How are load aggregators to be treated? We have gained a wealth of experience from the telephone industry about how much value they contribute, but the alternative service providers have nonetheless occupied a great deal of regulators' time thinking about how they should be regulated. What about the traditional anti-trust questions of when a market is contestable and when we can let go of the economic regulation? Is potential contestability enough? What's actual entry? We can draw on the experience of other industries, especially telecommunications. What sorts of minimal standards of service ought we be requiring and of whom? that.

There is the question of certain essential bottleneck facilities, more in terms of distribution wires than transmission wires, and how to regulate them. There is a worldwide discussion over price caps versus cost of service. In terms of unbundling the retail market, there are questions about who we will let do what in that market.

General Discussion

Question: I would like to raise the issue of the future of the service obligation. Who will be obligated in the future to be a provider of last resort, under what conditions, and, in fact, should there be such a thing?

Response: There should be a backstop in place, but it doesn't have to be the local distribution company. But I wonder why there has to be a local supplier; there is no default supplier of grocery or mechanic supplies, and I don't see ultimately what is different about electricity.

Response: If you look at the experience in other industries where there is no universal service requirement, it has not been a good experience. There is Insurance redlining by banks and savings and loans; minorities are still systematically discriminated against in obtaining property loans; in minority or poor communities, supermarkets charge higher rates for inferior goods. So there is some need for regulation, because otherwise the quality of service could decline.

Response: The obligation to serve needs to be redefined as an obligation to connect. But there is a physics issue in that a demand for electricity is met instantly, so there is no easy remote cutoff. Currently, having a default provider is unavoidable, but I think it is transitional.

Question: Default service has come to be not just a safety net for low-income consumers but also for people who choose not to choose. How do you set a price for default service that is not a disincentive for competition but not too high for low-income consumers?

Response: One of the challenges is to decide what mechanisms to use. The states have been very negligent in regard to low-income customers. There are competitive mechanisms they could use, acting as the aggregator and putting out energy service for bid, that would cause the price to go down per unit so that poor people would get more money out of the subsidy that was designated for them.

Comment: We need to design compensation mechanisms for distribution services so there is an incentive to serve underserved customers. We don't have universal service for electricity today; customers get cut off. Are we not creating problems wherein smart consumers will realize they can gain from this system? We're seeing this in telephones, where people run up large long-distance services, get cut off, and move to another provider. Telephone companies are forming business plans around low-income consumers where they charge in advance to cut service back if payments are missed; this is a tremendous incentive to pay for that service.

Comment: The Georgia General Assembly has dealt with these issues in the context of natural gas unbundling. There will be a trigger point at which the Public Service Commission declares that adequate market conditions exist and that consumers have 100 days to pick a gas supplier, at the end of which the PSC randomly assigns a supplier to those who haven't chosen and exits the market function. Gas marketers will not be legally permitted to refuse service to any customer who applies. This begins to address the obligation to serve. An article in *Public Utilities Fortnightly* laid out the details of the scheme.

Comment: On the issue of the difficulty of creating a structure in which the default service does not in effect reward passivity, Massachusetts has not resolved this question, but we argue that there need to be two fundamental principles in the design of that mechanism. One, the local distribution company shouldn't be obligated to provide that power supply through its own generation, but should obtain it from the power exchange. Second, theoretically, customers on default service should have the spot market price. We have been moving to put the default load out to bid and come up with an annual contract-type price. This begins to create an anti-competitive environment, so we hope to stay as close as possible to spot pricing in that mechanism.

Comment: The paradigm of consuming and then paying is not universal; often you have to pay in order to consume. In the UK, there is a power card that allows you to consume electricity on your card until it runs out.

Comment: These "smart cards," where people pay in advance, may give power companies a way to reduce the costs associated with collecting and billing, ultimately lowering the cost to the low-income consumer.

Comment: Regulators need to shift their focus from what they are not going to do to what they are going to do in the future. Regulatory commissions are deregulating without assuring that competitive structures are in place. They should ask themselves how they will assure that they as a regulatory agency have the skills and resources to monitor the competitiveness of the market.

Response: Although regulated competition is an oxymoron, almost all of our competitive markets have regulatory structures over them—SEC, CFTC, etcetera.

Comment: Whether the spate of consolidations that FERC is approving is going to result in gigantic companies with serious competitive problems five or ten years down the road is impossible to determine. An environment of small companies is highly unlikely, but preserving the competitive environment is difficult. So FERC tries to find authority in our statutes, for instance, under 203B, to preserve our ability to interject ourselves in the competitive marketplace in the future.

This brings up the question of how to measure the performance of the competitive marketplace and how to preserve the ability to correct errors as we make these incremental changes—approving mergers, adopting particular kinds of pricing mechanisms, establishing ISO criteria, and so forth-- without really knowing what the market will do with that down the road. It is a difficult time for regulators and, almost of necessity, we are beginning to foster a competitive market without having all the safeguards in place.

Response: There is an analogy to wireless telecommunications, where the FCC has an enormous battery of regulatory tools to ensure that competition occurs. States also need power to continue to allow barriers to entry to be eliminated, particularly in terms of siting of towers. There is a role for states in ensuring competition.

Comment: In California, market power was our top concern. Colleagues in other states are worried about stranded assets. But if you open up the market and there are only one or two players, then you have wasted a lot of time and effort. I am not sure I agree that once you deregulate, you are still regulating. If we get it right, we will have no more interest in generation.

Response: That is an interesting point for future exploration, because there are some real problems with using the anti-trust laws to deal with market power.

Question: What is the definition of retail competition? The power of customer choice depends on how informed the customer is.

With long-distance telephone service, no one can tell what the real price is. I don't know if we want to do that with electricity, which is a necessity.

Question: There are different layers in the system--commercial, operational, and planning. In retail unbundling, what is the commercial model that people want and how much of it do we have to accommodate? Do we have to set up a commercial accounting and tracking system which keeps track of the fiction about where the power comes from to satisfy a customer who thinks it comes from a particular place? Or can you get away with a very simple system, and then the marketers and retail competitors can figure out how to repackage that in different varieties and forms for the customer?

Response: We should have a simple system. We don't need to regulate the infrastructure of the electric system in a way that carries out that fiction, but there are things we can and should do to allow a company to package and sell a product. As long as we don't interfere with the way the system runs, we should bias ourselves towards allowing, for example, a green energy company to get to customers and sell their product.

Response: In a retail relationship with a customer, things other than kilowatt hours will be provided. By forcing customers to choose a supplier, that enables competitive suppliers to have the scope and the scale to innovate and be able to provide additional products and services beyond the commodity.

Response: The presence of a specific company does matter. This is about marketing rather than supply. One of the things that people talk about in terms of green marketing and green pricing is the ability to follow up where your supply came from and show that to the ultimate consumer. There are several approaches to how this can be done--through a complex set of tagging, Enron's proposal for a secondary market in wind credits or emissions credits, or through the generation performance standard. Generation performance standard at the retail level as proposed in Massachusetts and Vermont cannot be done without some kind of tagging system. To sell into Massachusetts, you have to assure that your bundle of supplies meets a pound-per-kilowatt-hour standard for emissions.

Question: It is not clear that everybody has adequate antitrust authority to deal with whatever issues of generation market power may be left after deregulation. To the extent that we continue to see problems of market power in the new environment, who should be and who is in a position to take the institutional lead in dealing with that?

Response: The enforcement mechanism is extraordinarily complex and expensive. We need to think in terms of a speedy and least-cost forum. The appropriate policy is to try to develop a future remedy so the historical facts do not repeat themselves. The alternative to that is to set up a pro-competition model. California had a maximalist government involvement in shaping the market structure. The fundamental policy question is whether we want regulators to be proactive, shape the system and then continue to sort out problems, or to continue to pursue an antitrust policy.

Should the remedy be breaking up the generators again or forcing more disaggregation? Is it to exercise residual ratemaking authority to control monopoly power, assuming that it can't be done through some market mechanism? Or you may conclude that there is no effective remedy. This raises the same questions about how the regulatory commissions react in a speedy fashion, given that you need to develop facts, but do not want to raise the cost to the point of being prohibitive?

Comment: Answering these questions knowing that there is appropriate price volatility in markets and distinguishing that from sustained market power exercise is part of the issue in figuring out remedies. I don't know if, short of the antitrust laws and litigation, the political institutions that look at prices are willing to tolerate the kind of price volatility that exists in many other markets, such as oil.

Question: In looking at unbundling and economies of scale in billing and marketing, can these be realized in an environment where consumers in different locations may have different rights regarding disclosure and the way a billing operation would be handled, e.g., calling an 800 number for account information? The ability to access these savings may be one area where the federal government has a role, possibly in coming up with a more uniform set of requirements. How do the opportunities for economies of scale relate to the state and federal distinction?

Response: There will be a need for a substantial amount of uniformity in, for instance, meter protocols and data transmission protocols. I am not sure that federal legislation is required. There needs to be calculation capability, but local software can be overlaid to handle or modify the output so that the engine can use it. As we go forward, rationalization of the disparate systems needs to occur. It will be in everyone's interest to come up with something that works across utility boundaries. Companies like Cellnet, which may be close to coming up with cost-effective automatic meter-reading solutions, may bridge that gap and offer their service to retail providers. So the result of a utility outsourcing may be that a competitive commercial firm will put multi-utility territories on a single standard.

Comment: I wonder how we decide fairness in terms of emission rights. Coincident with setting up a paradigm in which the newcomer has to comply with stricter and stricter controls, there was also cost-of-service regulation and not the same kind of competition among generators. The competition was one new plant against another. But now we are presuming head-to-head competition between existing and new, and no significant barriers to entry. The marginal cost to control the newcomer is extraordinarily high compared to the marginal cost to control the existing generator. We need to align environmental regulation and a competitive market. A fair way to dole out allowances is an auction.

Comment: New distributed generation technology has come about through R&D, resulting in lower costs for new generation. We do not quite see that in transmission yet.

In terms of regulation, the border of generation and transmission needs to be gray rather than having a definite line drawn, so that we see if there is generation benefit for a new fax technology.

Response: The gray area could actually impede rather than clarify investment. Greater clarification on this might be helpful.

Comment: On the main reliability system for SIPSCO, they had come up with a policy on line load relief. When SIPSCO realized that this might result in a 10 percent line load reduction, they needed to pay a higher price for interruptible customers within those areas and pay a higher rate to co-generation facilities in those areas in order to get more power into the radio lines. They wanted to roll those costs through the fax clause so that they would be compensated. We were being faced with incremental costs being passed on to our customers for what was really a transmission problem. This again raised this policy problem with us. If the This is a clear case of asking our native load customers to pick up the tab for a transmission situation.

Response: FERC should dust off the capacity reservation transmission tariff and put it in place.