Harvard Electricity Policy Group
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RAPPORTEUR'S SUMMARY*

Session One: Transmission Investment: Implementing Participant Funding

The "whether" of participant funding for transmission is a controversial policy question. The "how" of participant funding may be even more controversial and problematic. Even when participants volunteer to pay, it may be hard to define how much and to whom. The even harder cases will be when the imputed beneficiaries are required to pay. If some form of participant funding is required, how should it be implemented? The developing models in the existing and proposed regional transmission organizations illustrate how the rules have implications that transcend state boundaries, could influence all investment decisions from generation through end use, and may have substantial unintended consequences. How are benefits defined and measured? Who are the beneficiaries? As conditions change, how would cost allocations change? Who decides and who enforces? What would be the impact on investment and incentives under different interpretations of the broad principles of participant funding?

Speaker One

Although it was announced recently that SeTrans is suspending its operations, there is hope that an "RTO lite" can still be formed, by working with the state commissions and the stakeholder. SeTrans began with eleven and over time dropped to nine participants. It is unique because it is heavily populated by cooperatives and munis that actually own about 30 percent of the transmission in the south. Instead of starting a new organization from scratch or having a governing board comprised of stakeholders or independent business people, SeTrans wanted a third party, for-profit independent system administrator (ISA) to operate the RTO.

The ISA would collect startup and continuing operations costs, including a management fee that was its way to receive a profit through the RTO's transmission tariff. The management fee was incentive-driven. And SeTrans planned to use an LMP market closely modeled after PJM.

License plate rates would apply for all transactions synching within SeTrans and a through and out rate for outside transactions. This was critical because

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there is a lot of wheeling, particularly into Florida. Future transmission expansion was divided into either base-funded or participant-funded categories.

For SeTrans, participant funding is a way to fund upgrades to the AC network that does not roll the costs into the transmission rate base. Parties choose to fund upgrades in return for the economic benefits created, either in the form of new long-term FTRs or other property rights, such as qualifying as a network resource; in the form of lower energy prices in delivery-constrained areas; or in the form of higher energy prices in export-constrained areas.

In the SeTrans context, participant funding is a method by which the market participants themselves decide whether to fund an economic investment. If they do fund it, they realize the benefits crated by their investment. Those who pay for transmission receive the benefits. This also ensures that consumers do not pay for any investment for which they receive no needed benefit.

Why is participant funding so important to the region? It encourages siting generation that avoids fuel transportation costs. Much of the generation is being sited along the Gulf Coast and its waterways, primarily to take advantage of the cheap fuel sources without having to pay pipeline costs or pipeline expansion costs. Socializing transmission costs, at least in this region, will perpetuate economically inefficient generation decisions and cause generation to be built in the wrong places without regard to its effects on congestion. This effectively masks the very price signals that LMP is intended to provide. It discourages distributed generation and merchant transmission. Now that planning decisions are made by different parties participant funding is the only way that all generators face the total costs of their decisions, thus ensuring the lowest overall cost of system expansion.

Base-funded investments in SeTrans include those necessary to maintain standards of safety and reliability and serve forecasted load growth from qualified network resources as defined in FERC Order 2003 are the investments needed to change out, replace or repair existing transmission facilities. They are also the investments needed to maintain firm service commitments when the ability to honor such commitments is degraded due to circumstances outside the RTO's control, such as increased loop flow or a change in reliability standards that requires system upgrades.

Simply put, participant-funded investments are those desired by someone to make money or to save money and base-funded investments are those required to maintain the reliability of the system at agreed-upon standards.

Base-funded investments are made by individual transmission owners, included in their revenue requirements and rolled into the individual license plate rates. Participant-funded investments are made by market participants and are not included in RTO transmission rates. Assuming the investment creates sufficient new transfer capability for firm service, parties receive the right to receive firm service for 30 years without having to pay any congestion costs. All market participants including the vertically integrated transmission owners are required to participant fund facilities. Whether utilities can recover the cost of participant-funded utilities in retail rates is up to state retail jurisdictions: there is still regulated retail bundled service in at least one southern service territory.

Some argue that FTRs are not sufficient to encourage new investment in transmission. The real value is the ability to receive a lower delivered energy price in the case of a power purchases or to receive new firm service in the case of a new generator. If the benefits are not sufficient to incent the new investment, it is quite possible that the project is not economic to begin with. Participant funding provides a good economic test whether new economic upgrades should be built. The ISA is responsible for identifying possible economic transmission projects, but not for deciding whether they are built.

Another argument against participant funding is that it is impossible to separate reliability from economic investments. Almost all, if not all, transmission improvements have both reliability and economic benefits. The SeTrans planning process asks whether the project is required to meet reliability standards, in which case it is base-funded, and if optional, it is participant-funded. SeTrans does not separate reliability from economics. If customers do not need the reliability benefits, they do not have to pay.

There are some exceptions. For example, if a project lacks sufficient benefits for one party to participant fund, but has sufficient benefits for multiple parties, merchant transmission developers may be able to assemble syndicates of beneficiaries that would pay the developers to fund the project. Parties could also jointly fund projects and allocate FTRs among themselves.

If a participant-funded project delays or negates the need for a future reliability investment, the ISA has the discretion to determine the economic value of the delay or cancellation, provided that the reliability upgrade is real and already included in the regional plan. In that case, it can roll in the cost of at least the economic value of the delay or cancellation. If a participant-funded project degrades reliability or hastens the need for a reliability project or reduces the FTRs that were created by another participant-funded project, the ISA would determine the incremental costs that are created by the investment and charge them to the participant-funding party.

Whether a particular facility be base-funded or participant-funded will be determined by the regional plan and when the ISA decides what reliability projects are needed. SeTrans has a dispute resolution process, and I suppose FERC is the ultimate arbiter in most cases.

In the southeast, a transmission owner still retains the right to build transmission for its native load. The transmission would be participant-funded and the owner could only recover costs from its own native load. A third-party merchant may fund and build its own transmission. An owner building transmission on behalf of a funding third party could recover costs from that party only, but not in either transmission rate base or retail rate base.

A transmission owner has an obligation to build only where no one else has the right to build. In other words, if someone wants to participant-fund a project and has the legal ability to build it, there is no obligation on the part of the transmission owner to build. But if the owner is the only one who can build the project, it assumes an obligation.

In summary, participant funding sends the right price signals for efficient generator location decisions. It clarifies responsibility for transmission upgrades. It avoids having local load shoulder the burden for investments from which it does not benefit or from which it receives no needed benefit. Finally, it facilitates economically efficient expansion of the transmission grid.

Question: Explain a base-funded project for reliability only that also must address the needs to serve qualified network resources.

Response: To qualify as a network resource, you would have to participant-fund the project. Once you qualify, to the extent that network upgrades are needed to maintain reliability standards, including that network resource, they would become part of the base-funded plan. An exception is when a very inexpensive project creates additional capacity and it is based on the existing network that was already paid for by native-load customers. The utility acting on behalf of that native load would have a right of first refusal to build that project.

Speaker Two

PJM has been implementing a regional planning process. The original objectives as stated in its operating agreement were to allow for an open planning process that would let al interested parties in the region have input and participate to coordinate the wide range of needs for transmission capability and upgrades and coordinate across multiple transmission owners. This process was underway when PJM was deluged with requests for generation interconnection and it was clear that PJM needed a structured process to integrate those resources. As the markets evolve, PJM is integrating the economics needs into the planning process. However, these market-driven needs are not facilitated by PJM on a regulated basis.

Starting in July 2001, when PJM received provisional RTO status, it continued to develop merchant transmission rules and other elements of its planning process that would facilitate the ability of parties to introduce transmission upgrades on a purely participant-funded basis. Currently, PJM is wrestling with how to balance the range of market needs with the need to limit customer exposure to congestion. Demand response must be better integrated into markets, operations and planning. And PJM must limit the potential for the exercise of market power.

Centrally planned solutions divide between reliability-based or baseline upgrades and those that are market driven. Distributed resources can fit into either generation or demand sides. Obviously, much of the demand response that PJM will see will be driven by distributor resource technologies.

How one implements transmission for economics obviously affects the economic performance of the transmission system, but also the incentives or the revenue streams that may be available for generators to site in particular locations in PJM. It may affect the revenue streams of the transmission developers, including merchant developers.

Why would someone voluntarily pay for transmission upgrades when there is the possibility that PJM will assign them on another basis? PJM will offer a series of financial instruments to merchant transmission developers, based on the value their projects create. FTRs are the most obvious. If the merchant facility improves available transmission capability at the border, available transfer capability (ATC) rights go to the transmission developer. If you want to add a generator to the PJM system, it has to pay for upgrades to make it fully deliverable to the aggregate PJM market. If a merchant transmission developer creates incremental deliverability, it receives those rights and can sell them to any generator that wants to utilize the rights.

There are the reasons why a merchant developer might want to pay for transmission. PJM has ten projects in its interconnection queue, but none have moved forward enough to test whether these reasons are enough.

Generation developers may pay for transmission upgrades because they value the capacity rights that they will receive as a result or they just want to improve their economic delivery capability to more effectively participate in the markets beyond what deliverability would provide. And load can step up either through a merchant transmission developer or independently in order to limit its own exposure to congestion and derive the FTRs tat result from a particular transmission project.

On the regulated side, clearly PJM will always have to build for reliability. If the system is not compliant with reliability criteria in the future, transmission upgrades must be put into the regional transmission expansion plan to get back into compliance. Currently, there is a socialization of the costs on a zonal basis with a license plate rate system.

Anything PJM does for reliability will have secondary benefits; right now PJM only does pure reliability-driven cost allocation upgrades. It has not yet implemented any economically driven upgrades because that procedure has only just been approved. A delicate balance ties these elements together. Long-term adequacy – a critical goal in any regional planning process – requires both sufficient generation and transmission. If the market does not act fast enough, volatility will drive the need for regulated solutions. Cost allocation related to the regulated solutions will drive the behaviors of the market participants and may very well undercut the likelihood of the market-based solutions moving forward. We have to look at the revenue streams for generation, transmission and demand side in the context of the whole and make sure we are not putting something in place that solves one problem but backs us into a corner in another area. What we are doing, in-house, is assembling a package that works, and minimizes to the greatest extent possible, the potential for the exercise of market power.

Speaker Three

Participant funding is billed as the way to send efficient locational signals. To me, they might not be that much more efficient, and in some cases might even be less efficient. My concern is that participant funding is too much a source of litigation and delay, and disinvestments in the grid.

PJM has a baseline process by which transmission owners make the upgrades needed to meet reliability criteria and they are rolled in. Every six months, PJM opens a new tranche of generators that are placed by their queuing order. There is a system impact study for each generator, in which you add in one plant from the queue and PJM decs the other existing generation in proportion. It looks for a five or more percent impact on a facility that has become constrained by the existence of the new plant and determines what the upgrades needed to relieve the constraint. It allocates the cost of those based on the sum product of the generation shift factor and the unit size. Once you pay for the upgrades, you receive any FTRs that are created. The impact test is a simplification of what the actual dispatch would be. If you want to relieve a number of identified generation constraints, it seems to me that a package of upgrades should include scope and scale economies. One upgrade may make another one better, bigger or smaller.

What would an optimal grid expansion look like under perfect regulation? You look for the total delivered cost of power in net present value and put in demand-side resources and DSM when possible. Is there an optimal fee structure to charge generators so that you have the lowest total cost of generation and transmission? It is not necessarily economically optimal to charge generators for the total cost of expanding the grid. What you want is to charge them for the cost of expanding beyond the lowest-cost locations.

If merchant generators finance grid expansion and have to recover the cost of raising that money through some combination of ICAP and FTRs, you want them to have a locational signal, but not necessarily to have them fund virtually all the upgrades to the grid.

There is a feature in the PJM process in which the subsequent tranche can actually be charged part of an upgrade and almost rebate something to the prior tranche. It is a clever idea but I think somewhat complex to administer. Allocating upgrading costs to all megawatts may send the most efficient price signals; everyone who uses the constrained facility will know the shadow price of the new one. I think it will be especially difficult to implement participant funding or any grid expansion in regions that a still have significant integrated retail load. In my judgment, our hybrid system of partial deregulation is nearly unworkable.

The alternatives to participant funding are variations on rolled-in, embedded rates, ideally reflecting a least-cost regulated transmission plan, perhaps with some merchant. So-called shallow deep dimension is how the Europe describes the extent to which network upgrade costs are either allocated directly to the generator or to a small zone within the generator, as opposed to deep within the network. The differences from participant funding include less attribution of specific plants to specific upgrades; price signals that are spread among more users and perhaps more planning discretion. The potential for controversy and litigation may be smaller in the zonal approach.

The locational signals sent by participant funding do not seem to me to be optimal in the global sense. The question is to whom we send the signals and how large they are. I have not reached any conclusions.

I think bright lines are essential, but I also think that there may be scope for regional variation because participant funding versus the zonal approach may be preferable, based on some of the institutional features. Where there is no independent RTO, it is important that the rules are simple and transparent because there is so much planner discretion in deciding who pays for what. Perhaps some regions or nations will have an institutionally strong transmission owner sector that wants to stay in the transmission business.

If a slippery slope exists, it is because participants do not want to fund upgrades or they drop out of the queue, and eventually there will be a regulated backstop by which projects are rolled in. Regulators will not want to mediate disputes between entities that claim to be paying for reliability-driven upgrades that are really economic, or between generators facing participant funding that do not want to pay for their economic upgrades. Perhaps merchant transmission will look attractive because regulators do not have to make decisions, must as deregulated generation looked attractive to regulators in the wake of the nuclear cost overruns.

If we create a system that is too complex and contentious, we could push both federal and state regulators away from regulated upgrades in favor of letting the market do them.

Question: Does rolled in mean an automatic pass-through to retail customers?

Response: If you are vertically integrated you have both retail and wholesale rate bases. Presumably you would be able to roll the wholesale transmission rate into wholesale rate base. Whether you roll it into retail would be up to the regulators.

Question: Does the definition of rolled in mean that it will be part of the transmission embedded-cost charge? Is that a common definition for everyone?

Response: We really only impact the wholesale rate structure between what we do and what our transmission owners file in the FERC tariff. Ultimately, to get the bill back to individual retail customers, there must be a second layer that goes back to state regulation.

Discussion

Question: Are we desperately in need of transmission upgrades around the country? We know that the changing patterns of the wholesale market have changed the way we use the grid in ways that were never predicted. It is very difficult to anticipate what you need and how people will respond. To get the benefits, I think the critical requirement is making sure that the people making the decisions are mostly spending their own money, not other people's money.

Response: I think the industry has always built sufficient transmission to keep the system reliable. That does not mean that we have the most economically efficient system that has ever been built. Estimates to upgrade the system range from 50-100 billion dollars. The cost benefits studies about competitive markets that I have seen suggest improved efficiencies in the range of three to as high as ten percent. The 50-100 billion dollar upgrade estimates do not make sense to me. One solution is to return to centralized integrated resource planning. The other is to develop the bright line of reliability. I think you have to discipline yourself to say that the only costs that will be socialized are the reliability upgrades that are needed for the entire system.

Response: I do not think there is a desperate need for vast amounts of transmission, but there will always be needs here and there that will be addressed gradually in the planning process. The dilemma about adhering to a bright line test is that once you decide to base how your system operates and how you plan it to a large extent on markets, people will make mistakes and potentially will be harmed. PJM is stepping back to look at what it has missed over the past three years, maybe to reformulate a set of principles that will lead to a more complete solution, with input from the stakeholders.

Response: I think transmission is a service that lacks many of the attributes of a traditional competitive product. The benefits of introducing markets to electricity are in the dynamic elements. The realistic, workable way to achieve them is to enable politically acceptable, not just pragmatically functional, generation markets. As a nationwide investment in creating competitive electric markets, we must fund enough transmission to make them work well enough to be politically acceptable. I would do that by directly charging the beneficiaries. Certain infrastructure elements are needed to enable competition to work, and I think a certain amount separated by a bright line must be created.

Question: Do not worry about looking for a bright line because the areas that a few years ago were a congestion economics problem are now reliability issues to the extent that the ISOs are signing RMR contracts one after another. The difference is that now that we have created the markets, we pay generators at market-based prices. If we are now facing a huge amount of participant-funded transmission that is impossible to unscramble, how do we transition to a system of deliverability? How do we apply participant funding?

Response: New England and New York started a market without having LMP and participant funding in place. I think that if a generator wants to become deliverable, either in the zone it is in or for the RTO as a whole, it ought to pay whatever it takes to become deliverable. The fact that mistakes have been made does not obviate the need to establish a bright line and from that point forward, to make sure you charge the right prices in terms of LMP and participant funding. Once you start down the road of socialization, it becomes harder to get out of it.

Response: Stakeholders line up in favor, based on their bottom lines. It is not easy to put something together that everyone can live with.

Question: Could you comment on FERC's transmission incentives?

Response: FERC has proposed three incentives in its transmission pricing policy statement, that for the most part tilt toward the philosophy that more transmission investment is needed. You receive 50 basis points for joining an RTO, 150 basis points for divesting your transmission system and 100 basis points if you are able to invest in upgrades that can actually be sited, such as those that a siting commission might perceive as more environmentally friendly, or a technology that does not require stringing.

Question: What advice can the southeastern United States offer other regions?

Response: Keep price signals reasonable within a region. Do not force all of the costs onto the local region, or onto the exporters. Do not blame state commissions that question whether future benefits outweigh the costs of establishing organizations like SeTrans, because future benefits are difficult to predict. If FERC had just let the developing RTOs continue to tailor themselves to the needs of their regions, we may have been more successful in avoiding the federal-state animosity and changing the game midstream. If you know where congestion is, regulate its solution before starting the markets. In PJM, the ISO or RTO is supposed to price the estimate of a regulated solution as the market window opens. The original design allowed a generator to come into a load pocket without being subjected to automatic mitigation. Now the need to control market power conflicts with the need for some high price signals to encourage investment.

Comment: The ability of the system to remain intact and keep the lights on different from 1965 when NERC criteria developed. Frankly, we overbuilt the system to a large degree, but that was the context in which people looked at reliability. Today we drive the system harder. It matters if your lines are loaded up to 90 percent, versus 50 percent historically. From the standpoint of societal benefit, reliability projects can be forced, but we are looking at 35-year-old products or criteria in a completely changed situation.

Comment: We could make the system less reliable by building more transmission and incenting operators to locate further away from loads, but this creates all kinds of reactive power problems. When I hear DOE talk about a national transmission highway where you can build generation anywhere and transport it to any customer, it scares me. I wish more people would speak out about some of the problems that increasing transmission capability causes, as well as some of the solutions it may offer.

Comment: We generally attribute reliability to firm uses. If we want to go beyond that, we have to bring along the mechanism of paying for those upgrades.

Comment: One point we agree on is that whatever we decide to do for the purposes of reliability is a shared public good that all of us will fund. I think the hard problems arise when we hope to charge beneficiaries or let the market decide. I think policy-makers even above the level of FERC must rethink the concept of why we have a grid.

Question: PJM's grid is undergoing a massive transformation from one designed to serve the legacy generation that is mostly coal--or oil-fired to one that serves the new gas-fired generation that has located along the major pipelines. Who should pay for this transformation? Are we reaching a point where we saturate the easy sites for generation locating near gas supplies and as a result will look at a renewal of rolled-in funding for strictly reliability upgrades as new generators locate in amore diverse pattern across PJM? Will the generators end up paying for the majority of new transmission under this participant-funding formula?

Response: I have not studied this question. I think vertically integrated utilities in PJM would have been building gas-fired plaints at those same sites, with the costs being rolled into rate base. I think the situation could slip back to being all regulated, or regulators could tell the market to do everything.

Comment: There are studies underway to determine whether there is an economic value that could be assigned to reliability and whether a customer or class of customers should be priced accordingly. I think that new technologies in the next few years may well enhance available transfer capability.

Question: SeTrans proposed that a participant-funding party is responsible for incremental cost. If a project degrades reliability or hastens the need for a reliability project or reduces the available FTRs, could it be determined at the time a project is being proposed? If I figured out the costs of a project over a ten-year period, would that be integrated into the financial model for planning purposes?

Response: It is a one-time determination, based on the regional plan at the time and five to ten years into the future. The costs will be definite, but what the FTRs are worth beyond the ten-year period is speculative.

Question: The 2003 energy bill allowed individual transmission providers, RTOs and ISOs to make participant funding proposals. Could you comment on the independence issues?

Response: The language in the bill allows individual utilities to proposed participant funding. Such funding must be approved by FERC, be just and reasonable and not be unduly discriminatory.

Response: PJM's planning process is based on having an independent body making the judgments. You need a level of independence when there are so many stakeholders and revenue streams going in different directions.

Response: There is too much involved in implementing a proposal based on MW-mile approaches.

Session Two. The Impact of Price Caps and Rate Freezes on Service Quality

A frequent comment heard from all quarters after the August 14, 2003 blackout was that with rate caps in effect, utilities lacked any real incentives to spend on maintenance and operations. The logical deduction from such statements is that service quality is likely to decline under capped prices. Experience in telecommunications, especially in the Midwest and West, has reinforced that point of view. A number of states have signaled that they fear such an eventuality because they have tightened up their rules governing service quality. Is this common perception of service quality declining under price caps or rate freezes *accurate? Do frozen rates change incentives for utilities? Do they create a different set of incentives than regulatory lag did under traditional rate of return regulation? How should service quality be monitored and standards enforced? If service quality does decline, how should regulators respond? What incentives, if any, should be put in place? What sticks can, or should be wielded? Are there appropriate market mechanisms to be brought to bear, or should "old-fashioned" regulation be applied?*

Speaker One

Michael Clement's 2001 report on telecom examined quality of service from 1991-2000. It identified two categories: equipment- and system-oriented, and people- and process-oriented. The report found that companies gave priority to long-term investments in infrastructure, resulting in improvements in equipment-oriented quality measures, while the people- and process-oriented measures consistently declined over the period. This resulted in increased consumer complaints to state and federal regulators. And when regulators receive a lot of complaints, they start to react.

The electric and gas industries are more or less siblings, if not fraternal twins. Generalizing from telecom to electric is more of a stretch. Certainly both are network industries, but the degree of relationship is more like having a first cousin one generation removed.

Regulators involved in considering electricity restructuring for retail access were initially concerned about outage rates. The expectation was that under a rate freeze or price cap the industry would cut costs, especially in operations and maintenance (O&M). Another issue was the new industry practice of predictive maintenance, which differs from the more traditional scheduled maintenance of the systems. Predictive maintenance involves replacing elements in the system, based on logarithms that help predict failure: maintenance is then done "just in time" to minimize overall O&M costs. That is consistent with the incentive under price caps and rate freezes, but it does not necessarily lead to an economically efficient result. When people value the power that they keep more than the cost of the outage, giving utilities the incentive to minimize costs is perhaps wrong. Beyond any developing FERC regulation and the Mobile Sierra contracts, there is no real obligation to serve at a wholesale level. That was also a concern for some state commissions.

Based on a survey in 2001, most commissions responded that they relied on reporting and monitoring to assure reliability in service quality. Many had objective performance standards in place and several had penalties. Some states' objective performance standards are the outage standards. Standards used are: CAIDI, CAIFI, SAIDI, SAIFI and MAIFI: CAIDI, for example, is the Customer Average Interruption Duration Index, and MAIFI is the Momentary Average Interruption Frequency Index. Some states addressed tree trimming or vegetation management; others addressed poor circuit performance. Many state commissions had additional enforcement ability but it was not explicitly stated in the regulations. How large must a penalty be to matter, or does violating outages rates and so forth become business as usual? Do penalties actually reflect the value of service to a customer? What is the value of an outage to a customer? What is the cost of outage avoided? We still lack answers to many of these basic questions.

Regulators at least at the staff level are asking for the information that will allow them to begin to differentiate quality of service for customers who more highly value reliability. The information can also suggest where transmission and distribution upgrades and enhancements are needed, as well as influence O&M practices.

Bearing in mind that state regulation really focuses on delivering power to the end user, and hence the concerns about outage rates, we need FERC and NERC mandatory reliability rules. Commissions must react appropriately to ensure reliability to end-users without burdening the wholesale market. Other things must be done by states without retail access, such as reviewing purchased power adjustment clauses to provide good incentives to the utilities.

In the area of participant funding, who ultimately receives the benefit of reliability? Regulators must identify and make sure who bears the burden. Having the correct data could mean state regulators may find that the value of reliability so exceeds the cost of avoiding outages that increased investment and more O&M expenditures are needed. They will be able identify and provide these, or have the utilities or the market do so.

States need data to set correct incentives. Raising rates is easier when the benefits are demonstrated and the beneficiaries are the ones who pay. Rates may end up reflecting the customers' differentiated value of reliability. Some customers will also care about voltage sags, surges and harmonics, although most of those are already dealing with these issues.

Today's regulators are trying to get PBRs correct, although they lack perfect data. The future may bring differentiated rates for quality of reliability and services. Having the data may help regulators tie together retail and wholesale transmission levels more beneficially.

Question: Are vegetation management standards focused solely on the distribution portion of the system?

Response: Some of the western states that experienced the outage of a few years ago have said they fully intend to apply outage standards even at the transmission level, to make sure utilities' tree trimming and vegetation management programs all the way up and down the line. But what do you do when you are subject to an outage standard but something happens upstream beyond your control? NERC mandatory standards will help in situations like this.

Question: Did the Clement study conclude that the simpler and earlier model price cap plans have a better effect than the later, more complicated performance plans?

Response: Yes. But if you focus too much on PBR, you may end up overspending in certain areas. This is why PBR is an imperfect solution. Again, there is no good data on the costs of outage avoidance versus lost power value. Certainly, there are political questions. Do you invest billions now, or is there a less costly solution? Future investment may be needed, but in what quantity?

Question: Have predictive versus scheduling maintenance approaches been compared? Is there data from other industries on mechanical equipment and the ability to use predictive maintenance techniques to control O&M costs and better maintain your system overall?

Response: No. Analogies to other industries are not quite the same thing. People are very inconvenienced by outages.

Question: Will we go to value-based electricity pricing?

Response: Ultimately, I think we will have more price discrimination and it will be based on the value of reliability. That will be one way that regulators can tell which end-use customers require an investment and will pay for the participant funding because they are the beneficiaries. The needed equipment and O&M investment will probably be financed that way. This is years, but not decades, away.

Comment: It is reminiscent of the telephone industry saying: "We will charge you for service, but if you want dial tone, that will be extra."

Question: Is there a statistical correlation between CAIDI, CAIFI, MAIFI performance standards and FERC Form One data that show O&M costs are higher for better reliability?

Response: There is no national study. We do know that when a utility spends on vegetation and tree trimming, whether or not it spends more money overall, this shows up on FERC Form One.

Speaker Two

I am an advocate of incentive regulation, meaning I look at it first when trying to find an alternative to rate-of-return/cost-of-service regulation. Incentive regulation is not always "one size fits all." When I advise a regulator or a utility I make it clear that one enters into this carefully so there is a proper fit. However, I wonder where we are going.

Incentive regulation in the US started with the railroad industry as a cost-based, or input price-based recovery mechanism. Now it is used in many industries. Earning sharing mechanisms (ESM), very common in the telephone industry, are the most common incentive regulation in the electric industry, in combination with a price freeze or a rate cap. I view ESM as a transitional mechanism that allows regulators and utilities to move from rate-of-return to a comprehensive incentive regulatory program.

Historically, the Federal Communications Commission (FCC) was prominent in developing incentive regulation for the telephone industry. However, when you look around the world, it seems to be more difficult in both electric and natural gas, to move to this regulatory mechanism. The question is whether you can devise an incentive regulatory structure that works with the market structures to encourage transmission owners to invest.

Question: Has anyone examined non-regulatory factors that may have an impact on telecom, such as a corporate decision to invest offshore, or to invest in other industries?

Response: Those decisions would have been made under any regulatory mechanism and cannot be related to an incentive regulatory structure.

Speaker Three

The principal national concern about quality of service is related to service interruption in its various guises and thus to transmission and distribution standards, and to the adequacy of access in high-usage areas to low-cost power generation sources. While not new, this problem will certainly intensify as the economy recovers. Based on the August 14 blackout, we realize things are not as good as they ought to be.

A principal reason for this is the disjoined federal-state regulation of transmission. Perhaps it will be shown that some of the new approaches will streamline or override the usual stalling in siting transmission facilities. In the past, local procedures have trumped national priorities, with a negative effect on network stability.

In examining telecom to discover whether price caps work, in the first round of the election of price cap targets by the regional Bell companies, five out of seven adopted the most aggressive cost-reduction targets to avoid gain sharing altogether and retain the profits earned beyond the caps. The companies prospered. However, based on the evidence they presented before the price cap regime went into effect, the companies claimed they could not recover the cost of interstate service; costs would continue to rise; and quality of service would decline. In the second round, price cap targets were raised substantially, and again five of the seven regional Bells elected the most aggressive price cap targets, protesting that they would be severely disadvantaged. NYNEX even said it would be bankrupted. The companies prospered. In the third round, the FCC set a single price cap target of 6.5 percent per year. The Bells claimed that their productivity growth could not exceed two and a half percent per year and that their costs rose at the same rate as national inflation. I do not know if anyone really believed that the technological change in telecom was such that this statement was true.

The telecom lesson suggests that under appropriate incentives, regulated companies regularly find ways to improve efficiency. And the FCC had relatively effective quality of service monitoring guidelines that were generally accepted and administered by the states. Under both sets of the FCC's reporting and measurement criteria, the relationship between total factor productivity and service quality was negative for most telecom companies. However, as long as it seemed satisfactory, the issue of telecom service quality was not recognized. The interoperability of telecom networks requires uniform communications protocols and more homogeneity than electric power transmission requires. There is consensus about the required elements to run a sensible telecom network.

By contrast, FERC has much less centralized authority in general than the FCC. Electric power has more heterogeneity; generation technologies are more state-specific and even company-specific. High transport costs for coal and oil and the availability of natural gas also add to the peculiarity.

While it is true in telecom that there are political bargains trading off higher rates for more high-paying jobs, it is more so in the electric industry. Power companies also pay a high rate of state and local taxation and under restructuring the question of what would replace older plants that closed down was an important question. Load pockets that developed and were permitted to persist substantially benefit some groups: instead of transmission, high-cost generation facilities are built to serve the load pockets. Large, stranded assets are perhaps become regulatory assets.

All of these problems can perhaps be best analyzed in terms of technology interacting with state regulatory environments. For example, it boggles the mind that employees of some state commissions must wait two years to take a job with a company they have regulated, but the commissioners can take a job tomorrow. In 1995, a large urban utility with fewer than 3 million customers had authorized public service expenditures of 110 billion dollars annually. It all went into rate base. In some cases, the discrimination favoring particular industrial customers is very surprising.

The service life of major assets or service lives in telecom is much shorter than in the electric industry. Incentive regulation is hard to start and the net incentives still may be perverse in such an environment.

In these industries, monitoring or auditing have never been as forceful or effective as we might idealize. It is more severe in electric power because of technological diversity, long-lived assets and state-dominated regulation. Devising incentives is not so much the problem, as the context: the environment in which the incentives would operate is the problem.

Speaker Four

Other countries can offer us lessons about price caps that we can apply and tailor to the circumstances of a particular utility or region. I think there is a common perception that they degrade service quality in electricity. In the last three years, the UK has spent millions on consultants and staff time, looking at service quality issues in the past decade. When you measure service quality by the frequency and duration of interruptions under price cap regulation, some utilities decreased the number of outages and their duration by over 25 percent.

However, rate of return regulation offers examples of bad incentives for poor financial performance and other shady deals, and also poor service quality in some areas. Around the world there are examples of state-owned companies that have vested political interests in keeping rates down and other background issues.

What we want to cap could be the prices on energy only, wires charges, a bundled product, or metering and billing. The costs must be controllable. In California's mixed bag of regulatory mechanisms with competition at one level and regulation at another, for the most part the energy costs were not controllable, making the regulatory tool of price caps pointless. If utilities do not or cannot control costs, they must hedge, which will raise issues with regulators.

In the UK, the wires companies face a cap price per kWh for wire services. The incentive to expand throughout has been so great that the utilities make huge profits. When the regulator realized this, it instituted a cap for part of the revenue requirement to dampen the incentives, and this has resulted in new concerns about service quality. There are separate incentives for service quality that are tied to the utilities' allowed revenues and the issue is dealt with separately, unlike the US. Although we have some good incentives for price caps, less consumption is a strong incentive for utilities to cut service quality. For at least five years, the UK has had penalties for appointments not being met or for service not being restored within three hours that range from about US$30-100 per customer. Data on the number of payments made in any particular year show less than 20 per utility. That appears to be a strong enough incentive for the utilities to meet their customer service standards.

I think we can talk about the same kinds of incentives for bundled services, but we need some accounting separations among the different parts of the supply chain to avoid cross subsidizing. We could separate service quality from price caps or rate of return and institute a penalties and rewards system for meeting targets. We could benchmark the utilities and publish the findings.

In theory, there is no incentive to cut costs in rate of return or cost of service regulation. However, with regulatory lag, that incentive does exist. Is this incentive stronger than it would be under price caps? Experience in other parts of the word shows that the incentives are much stronger in price cap regulation than with regulatory lag.

Discussion

Comment: I do not think that service quality is one of the unintended consequences of deregulation. Under rate of return, I would say there is an equal incentive to reduce O&M costs, because who wants to come before the commission for a rate case every other year? The diminution in the quality of service, however, has occurred for several reasons. It can be a good exit strategy for a company that wishes to be acquired, like Ameritech -- the most profitable of the telecoms in the mid-1990s. It was sold to SBC and the service quality dropped: Ameritech had cut everything to the bone. Another reason is that Wall Street was telling the regulated companies that shareholder value was what it was all about. Some companies then undertook strategies that took them far from their primary lines of business. Supposedly there is a firewall at least in terms for financing, between a regulated parent and its unregulated subsidiaries, but regulators do not know what companies do with the dividends they pay to the parent. When Wall Street saw that ventures into unregulated businesses often did not fit, now it likes regulated companies and loves rate of return. I am unconvinced that quality of service troubles have anything to do with restructuring or rate freezes.

Response: If regulatory lag is long enough, it acts exactly like a rate freeze.

Comment: Rate freezes and price caps enshrine regulatory lag in a much more formal arrangement because the issue about whether the existing rates under rate of return regulation can be re-opened. The initiative is usually with the utility, but not necessarily.

Comment: A more robust form of service quality regulation exists for wholesale telecom. It is easier to audit, penalize or change what is being measured.

Response: To provide in-region, long-distance entry, the Bell companies went through a rigorous process before state commissions and the FCC. This resulted in very thorough wholesale level measurements, coupled with enforcement.

Question: I agree that we can design a PBR mechanism with protections for service quality deterioration. The problem for electricity is that it gives you an incentive to increase throughput that runs counter to the conservation ethic and energy efficiency. How do you rationalize any rate index with DSM and the energy efficiency ethic? If you set up a benchmarking index, a large company could influence it through its buying, selling or storage actions.

Response: It can be argued that a pure price cap encourages increased usage. In telecom, this increase is good, but in energy industries it is a negative. If you are serious about usage reduction, taxation works better than anything else.

Response: Use a revenue cap instead of a price cap to make it attractive to the interest groups.

Response: At least for distribution and transmission, revenue caps are becoming more commonplace throughout the world. In terms of having a benchmark where someone has a huge influence I think it is dangerous because it creates all kinds of bad incentives.

Question: In transmission, it is easy to understand how to set standards, like how many trees are trimmed. But it is more difficult to set up and define the services related to outputs. The UK's transmission service is provided by a monopoly and acts as though there are no constraints anywhere in its one zone. Given the number of constraints and the large regions here, I cannot imagine that the US is prepared to authorize rates high enough so that the transmission company can pretend there are no constraints.

Response: OFGEN, the UK regulator tried to move to LMP and to a more rational purchase of ancillary services, but its governance structure required unanimous approval by its stakeholders. This is one reason for the new electricity trading arrangements seen in the UK. Maybe the transmission operator should sign contracts instead of going to the spot markets for some services. If the spot price is less than the contract price, regulators may decide that it is not prudently incurred. You have to meet quality standards and I do not have a sense of how to resolve that.

Comment: Measuring output is essential to building in a price cap or other incentive regulatory mechanism that will allow efficient investment decisions. The delta that results from additional transmission investment is additional reliability and a societal benefit from decreased congestion. I have not heard of a solution to incorporate that and not have countering incentives for the transmission owners.

Question: Could incentive mechanisms fit within adjustable formula rates for transmission?

Comment: FERC occasionally has alluded to a mechanism that establishes a correct rate of return and applies it through a formula to establish a rate for transmission service. Most price cap mechanisms allow you to keep the savings over and above that determination for a few years. Some people are recalibrating the rate annually so that you cannot keep those savings over a period of years.

Response: You may be able to connect to a rolling measure of the shadow cost of the facilities being used. Maybe you can adopt different time windows that you use to calculate the rate by formula that you use to levy the charge. Peak load pricing is somewhat similar.

Response: If you reset annually, do not reset completely down to the costs. Give the utilities an incentive to cut but keep some of the costs.

Comment: FERC is faced with not wanting to do traditional rate cases for the transmission assets that it may be regulating now through unbundling. A formula rate reduces the administrative costs. Formula rates also align transmission owners' incentives to expand the system with what FERC would like.

Comment: Reducing administrative costs sounds like the fuel adjustment clause we have at the retail level. A capital adjustment clause seems a bit dangerous because no one oversees whether an investment is not prudent, nor do you want to degrade reliability.

Comment: At least in some cost case I do not think you are determining whether a transmission expansion would degrade FTRs. FERC is trying to exit the ratemaking business, just like it is trying to get away from reviewing purchase power contracts. We are supposed to be going to wholesale markets. The RTO should determine prudence.

Comment: The RTO will always be approving a piece of transmission before it is ever sited. It almost never happens that something is built that an operator says is unneeded.

Session Three. Successful Market Design: What Should a State Want?

Whether in creating a new system for coordinating transmission use or in joining an existing regional transmission organization, the transition presents state regulators, companies and other responsible parties with an array of choices. Separating good from bad design is a challenge. Separating what is necessary from what is optional requires care. And choosing among the options can be a daunting and confusing task in any region. How can native load be protected? How should we treat existing contracts? What should be the initial allocation *of financial transmission rights? How can different retail choice regimes work under the same wholesale market? How should we treat stranded transmission revenues? What must be done to accommodate regional scheduling and dispatch requirements? What should a state want, and how can it define its choices?*

Speaker One

Returning to the basics, how can a state structure its regulatory system and the functions of its utility to ensure that customer service is the lowest cost and most reliable? Obviously there would be some regional trading; the benefits of that must be captured for both consumers and producers. If the answers coming from the bottom up are similar to FERC's top-down approach, perhaps there is more room for discussion than we have thought.

Can security-constrained, centralized economic dispatch – the thing that keeps the lights on – be used to build a successful design methodology that is consistent with our need to support reliability, maximize the benefits of our trading and minimize our risks? This dispatch allows you to use the lowest-cost generators that are available to the system operators to serve load. Think of it as almost a contract between the regulators and the system operators.

All entities inside and outside a region should have the ability to offer power. These used to be called economy transactions, economy sales or economy purchases. System operators acting in the interest of the public and their ratepayers would want to select the least-cost mix. Each utility or each region wants non-discriminatory access to every system, with fair rates for usage and fair procedures when congestion occurs.

The principle of marginal cost pricing means that if you charge anything less than that, you subsidize the transactions of others. They will simply use your grid more and you will be paying. If you charge more than the marginal cost, they would subsidize you. We would need to schedule transactions on the systems. Inevitably, we cannot perfectly track the amount of generation being injected and the amount of load being withdrawn, so there must be a fair method for charging these imbalances.

Dispatch kicks in when an imbalance occurs. If there is too much generation, the dispatch turns it down at whatever the marginal cost. To capture the economic benefits of dispatch that occurs every minute of every day across this country, we need only price it correctly. Using marginal cost to price the dispatch also has important reliability benefits. For example, if you pay or charge people at marginal cost for generators that respond to the dispatch, the dispatch signals and the prices are in perfect alignment. It is easier for the system operator to keep the lights on when enough people respond to the right price signals and follow the dispatch.

If using the grid causes congestion, there are three methods to handle it. One is to say that if we think your transaction will come on our grid and cause congestion, we will not even let you schedule it. Second, if we think your transaction might cause congestion on our grid, we might let you do it, but if it forces us to incur re-dispatch cost, we will curtail you through TLR. Third, if your transaction might cause congestion on our grid and we can re-dispatch our system to accommodate it, we will charge you the re-dispatch's marginal costs, or the rebalancing costs.

The net result of this mix of buying and selling, scheduling and balancing is that we serve native loads reliably at the lowest cost. The purpose of transmission rights is to give people a hedge or a cover for the re-dispatch costs. We avoid transmission line load curtailments because we are willing to pay the re-dispatch costs because we have the rights to cover them. If we are willing to pay anyway and might not have the rights, we avoid TLRs.

In summary, it is possible that even without FERC, without mandates, without SMD, we will naturally gravitate naturally to an ISO, which gives us a common basis for discussions between federal and state regulators.

Speaker Two

Last night when I could not sleep, I turned the TV on and watched a Tony Robbins infomercial. Tony was talking about his new CDs. The first one tells you how to lose weight and actually build muscle. I thought lose weight, build muscle sounded good. The next CD helps you to build relationships. That also sounded good. Another helps you increase your wealth. And another will help make you a happy person.

And if I take his personality test, Tony will send me a confidential, personal 30-page profile, and a diary in which I can keep all my charts and goals and wishes and wants, to help me become a better person.

But then he says I can have all this for three easy payments of $69.95. I began to look at what he was offering me and it was not very much. I turned off the TV and went to sleep and I still have $210 in my back pocket.

To the southeastern US, a lot of SMD and RTO is about selling us things we already have. When regulators looked at what SeTrans was really offering, there was nothing there that we did not already have, and we did not have to pay an extra price to get it.

As a regulator, my role is to offer my consumers affordable, reliable electricity. That is it. That is all I want to do. My state's utilities have been under performance-based rates since 1986. Every year they rank in the top five of J.D. Power & Associates. Only one percent of the complaints I get at my office deal with electricity, and most of those are from consumers wanting bill extensions.

When you ask me to help the wholesale marketer change the way we do business, you are asking me to take an incredible leap of faith. Commissioners in the southeast are elected. The last thing they want to be saddled with is a reputation for destroying our great electricity system.

The only regret I have in my first term was an early mistake I made. My state has an abundance of merchant plants. They receive a certificate to operate, whether or not they are regulated. As I reviewed the situation, I told the staff that we did not need to approve more new plants. That was hard for my colleagues because some proposed plants were in their districts. There were also resolutions from some of the mayors, cities and counties, claiming that these new economic developments would help their school systems and their tax revenues. My staff experts pointed out that the proposed merchants were businesspeople who would not come to the commission unless they thought it was the right thing to do and that financial institutions would not lend to them if they thought they would go bankrupt. But it is a mistake to assume that a businessperson or a financial institution knows what it is doing when embarking on a project. We are now saddled with 13,000 MW that we do not need. Recently, we met with the merchant plant representatives to discuss incentives and other things to help our state. We are willing to shut down some old plants in favor of their more efficient plants and savings may come from fuel.

Because of the merchant power glut, southeastern states are open to change. Commissioners should understand, however, that the amount of electricity owned by our integrated utilities could affect the cost-benefit relationship. I think we need a third party that helps with IRP, cost allocation and participant funding. I think incumbent utilities must include the merchant plants and independent transmission providers in the planning process. An independent third party could help with security coordination and TLR design, as well as OASIS administration. The southeastern US could do a better job on information flow. We also need a good escape plan if this does not work. If it does work, we could go to a full-blown RTO.

I am a believer in regional differences. I do not think you can standardize the market from coast to coast and from Canada to Mexico. Every area of the country has a different mix to generate its power. Some states are a hybrid of regulated and deregulated activity. It is important that everyone research and manage what is best for their region. Much of the pushback the southeast gave FERC stemmed not from unwillingness to look at different market designs, but the fact we have so much to lose. I do not think there can be "one size fits all," but we can be open-minded about the things we can do that will best serve our customers and our constituents.

Speaker Three

I come from a regulated state and am a firm believer that states have a vital role in market design if it is to be successful. I am also from a state that produces 97 percent of its electricity from coal. Electrons, IPPs and regulated utilities cross state borders, but I cannot cross them as a state regulator. State regulators also have to deal with the results of the Energy Policy Act; there has been a wholesale market for ten years. Since the market is also interconnected, he bottom line is that my ratepayers should benefit. President Eisenhower once said that our united forces for our communication and transportation systems are dynamic elements in the very name we bear – United States. Without them, we would be a mere alliance of many separate parts.

What role does my state play? We want a grid that is as reliable and economically efficient as reasonably possible. We have all learned from the August 14 blackout that we must speak the same language if we want to communicate. We must have common definitions and standards, and we need to see the transparency.

By their self-interest, stand-alone utilities demand confidentiality of their data. It falls to someone outside these utilities to have the oversight across all borders that traditional regulators alone cannot fulfill. But as state regulators, we have been forced to consider how security-constrained economic dispatch affects reliability or any number of unexpected forced outages. We look at the elimination of pancaked rates under the design of reliability and think about how economic disincentives sometimes fail to allow the most reliable transactions to occur. We are learning that a good design includes FTRs, LMP and re-dispatch. States do not want their ratepayers to subsidize reliability that could have been assured by clearing congestion.

Coordinated planning is part of reliability. It must be planned in a regional manner because that is how transmission and generation occur. A successful market design also makes good business sense. The essence of a well-designed, reliable and cost-effective wholesale market design comes home to roost in our retail rates, and all regulators are aware that this is the very base of our retails.

Speaker Four

On the issue of state versus federal, everything we do stems flows from the interstate commerce clause. Part of the concern is that Congress has not acted, so my argument for the efficacy of states is that they add value. If there is a systemic failure within a region or a political failure, maybe there is a better argument but I do not think the argument in favor of systemic failure is as powerful as the one for diversity. If one part of the country gets it wildly right, another will simply have to respond and we all will learn in order to be viable. The absence of an expressed industrial policy is itself an industrial policy. The absence of an expressed or articulated market design is itself a market design of some sort.

There are more independent generators with no obligation to serve in every region, including the west. Reactive power has been a concern for at least ten years, although it was not part of the discussion or identified in contracts. More transactions occur on vertically integrated systems. There is increased fragmentation uncertainty and competition and decreased cooperation. We do not know the correct levels of investment in generation and transmission. We are finally aware of the degree of coordination between the electricity and natural gas systems.

The top-down approach to SMD potentially was in the name of a good goal, but it has been a powerful distraction from moving forward on the issues based on the RTOs. The western states have real operational differences and degrees of system integration. At the moment, Montana is the only state fully exposed to the region. Just as the southeastern states have their own history of federal/state relations, states in the west are concerned about control and accountability, particularly in natural resources. I cannot overstate the value of civic participation that is the counterweight to the democratic failure argument made in favor of federal intervention. Would it have been different if FERC had developed bottom-up approaches convening by regions?

In RTO West, an eight-year effort finally culminated in a good filing. FERC's RTO West filing backed off the one nation, one grid approach and moved to a more thoughtful assessment of the relationship between SMD and RTOs. Nonetheless, the proposal ran to ground for several reasons. In pursuing consensus, some of the tough issues had been brushed over. In June 2003, the states asked RTO West's proponents to undertake more focused discussions. The reactivated group looked again at what made sense for a regional RTO, developing three options that were problematic, but in talking about the commonalities, led to a phased, three-stage movement to a hybrid RTO. This approach will at least allow us to go forward with some of the critical details. Finally, I am encouraged by other regional activities such as the regional governance project being pursued by the Western Governors Association and CREPC.

Discussion

Question: Would the 13,000 MW of excess capacity in your region have been better rationalized if an organized market were already in place?

Response: Our incumbent utilities are long, as well, so we have excess electricity everywhere. The rationale of targeting one of the incumbents is that efficiencies could be realized by decommissioning some of its old plants. In 2000-01, some people believed that the merchants were seeking to ship southern resources to the northeast or to the Midwest. That is unrealistic; it would have been more cost-effective to move the plants closer to the load. But at the time of approval, there were many political pressures. Now the issue is how to get the best use of these plants. There is nothing that tells me that we will have cheaper power by having a transmission operator and bidding by distributors and generators. In fact, we will lose money because the price we pay to put in an RTO will exceed the benefits we receive from the power. SeTrans failed because it could not sustain itself. It is obvious that FERC dislikes the market we have in the southeast, but we do have one in which companies purchase wholesale power and we audit the transactions at different times.

Response: Under the traditional system, there was a fairly good allocation of risk. One of the arguments for an unbundled, restructured approach is that there are no stranded costs in a market; the risk of development is entirely on the developer and the shareholder. It is very difficult to receive financing in an unbundled state if you lack a contract, and you need pre-approval to receive one. Everyone wants a piece of default supply, which has become a big issue, rather than an afterthought. There is real potential for risk to be other than on the shareholder. I would not want to be in a position to approve a competitive merchant plant. To the degree that regulators are involved at all, arguably that gives the merchant developer a right to seek cost recovery.

Question: The regions of the US differ politically and culturally, but the standards for system operation should be the same for all control areas. How do regional differences matter, other than in the political realm?

Response: An electrical cooperative or TVA serves sixty percent of my state. There are differences in how systems have been built. People have different measurements, even if there are no incentives or penalties.

Comment: I agree that from an engineering perspective there should be a lot of commonality, but there are operational differences depending on your system's configuration.

Question: Do we need reactive power pricing?

Response: Yes, but I am not sure how easily it lends itself to a market. For example, in PJM if a generator follows a dispatch instruction, it will not be harmed financially and so you put in opportunity cost payments. The absolute financial underpinning is when a unit must forego an energy payment to provide what I would call a reliability service. If a generator cannot perform according to its bilateral contract, we need a replacement because electricity is an unswitchable network, unlike telecom or gas. I think we can all agree that we need security coordination, OASIS administration and the administration of transmission rights. Stack the 13,000 MW of unused power cheapest to most expensive, and use the lowest cost first. That would be good for your customers.

Response: I disagree on the gas and telecom analogy. Unlike your electric bill, when I regulate the distribution cost of the gas company, I do not know the product's cost. That is why we bend over backwards to hedge and try to stabilize that cost as much as possible. I oppose a market in which the integrated utilities are only distributors and we are at the mercy of and independent system administrator that supplies our daily megawatt load. I am for allowing the integrated utilities to maintain their generation, supplementing it with merchant power if it is cheaper. Frankly, it is difficult for a power marketer to build in my region because of the local utilities' bond ratings and financial clout. Our problems are an aging generating fleet and what will happen when demand eventually outstrips supply. Politicians and regulators must understand the competitive market they are setting up and be prepared to live with the consequences because it is unfair to expect a business to take a beating when prices are low but take away its profits when the situation turns around. A regulator's consumers and constituents want stable prices and reliability. They want to drive to town to pay their bills and see a utility's employees interacting with their community. An integrated utility is probably not the most economically efficient, but some inherent inefficiencies are not the worst thing to have.

Response: If there is all this extra generation sitting around and any of it is lower cost than my local utility's generation, I would want it dispatched. My prices would go down and I can help lower costs. I want to demand open dispatch if I do not have it. I want to make sure that people are compensated at a price that correctly values their energy at their location. The price should be the same if efficient regulation equals efficient markets. If my local utility tells me that it will take my power but will not pay me the marginal cost of providing it, I would not expect it to be provided. I would not be receiving the benefits and I would leave money on the table that should have gone to my ratepayers and investors. Are 13,000 MW of surplus productive capacity sitting in a low-cost region when all around the prices are rising a problem or an opportunity? I would want someone to tell the neighboring states to open their transmission, spot markets and dispatch and pay me the value of the product my state products because that will bring me jobs, income and tax revenues.

Comment: To the extent that your local utility has an aging generator fleet and a regulatory contract to serve native loads, it can serve its load through a combination of the low-cost fleet and the IPPs that are economic to contract with.

Comment: Add to that combination the fact that the regulated utility could cross state lines or have an IPP in another state. As for an independent third party, the MISO states created an organization to insist that the third party be independent and transparent and monitor the markets, although it was never initially thought to be an operator or market manager.

Response: In telecom, some regulators have tried to make the internal systems such as operation support systems of the vertically integrated utilities, such as pre-ordering, ordering, provisioning, maintenance repair and billing, both external and explicit. Note that problems have arisen from making simplistic comparisons between telecom, gas and electricity. I think there is a false dichotomy between markets and regulations. Efficient markets have rules, many of which are implicit and based on history and consensus. Common law, contract law and uniform commercial code are all economic regulation in a sense. Regulation is part of the move from state to private ownership and toward liberalization.

Question: Are cost benefit studies done after each step or at the end in RTO West?

Response: Some benefits may not accrue for years. We only think in four-year windows from a political standpoint. Regulators want to be careful about being too tied to cost-benefit approaches. Taking small steps means that we can implement something for a short period and move on to the next step if it works, and if not, we can easily get out. I think most commissioners can live with this approach.

Response: Implementing LMP through an RTO is expensive. I would encourage a cost benefit analysis that looks at costs like TLR that are buried in the system today. Perhaps RTOs should be required to report their cost-effectiveness so that regulators and customers can understand it.

Response: Cost benefit studies are usually endorsed or rejected, based on where you really want to go; they are assumption driven and they are necessarily static. There is also the question of "but/for" as in, "But for this approach what do we do?" Using a staged approach, provided it does not simply defer the tough issues, conceivably could increase some costs, but is more likely to get you to a workable solution. A neutral cost benefit analysis should offer feedback about the most sensible designs and the modifications or reevaluations that will increase the benefits.

Comment: My experience is that you do not learn from others' mistakes, but from the ones you make. PJM first put in a zonal pricing system in 1997 that was a catastrophic failure and almost caused the lights to go out. Shortly after, New England put in a zonal system and while the lights did not go out, power plants were built in the wrong places. Next, California's zonal pricing system revealed the same predictable problems. Now Texas is trying to undo its market design. People need to look more closely at cost-benefit studies.

Question: Who bears the residual revenue responsibility for a transmission system?

Response: New costs appear to be added costs because we have not considered the costs that are already embedded. LMP was fought against, and other schemes were tried, but each failure has led to the conclusion that LMP is the most logical way to handle the situation. Transmission pricing may evolve into the same answer.

Response: The irony is that unless you take the CATO approach, you are socializing and regulating ore heavily one part of the network – all in the aid of a free market. Although there is a tendency to relearn the same bad lessons, the Federal Telecom Act codified some provisional conclusions by the states and prematurely limited the amount of experimentation. Even when the Eight Circuit stayed the FCC's wholesale pricing rules, states were able to adopt some variations, so there has been some positive benchmarking state to state and region to region.

Comment: While some regions have consensus, others have extreme polarity. States that have overlapping systems need to figure things out, either with their governors or their legislatures. If they cannot do that, the choice is to turn to a federal entity -- whether FERC or the Supreme Court. In the south, it is not so much a fight, but that the states want to do it their way

Response: Because the reality of the regional nature of systems changes the answer that a regulator will give, an independent third part is needed. The overall assumption must be that the borders are changing. Utilities also face this.

Comment: Our century-old national electric system was built with investor-owned utilities, coops, munis, power marketing agencies and federal corporations. It has a few hundred control areas. The question is how to consolidate to fit today's reliability needs and the economic needs for trade? After the 1965 blackout, he small states in New England understood that they could not stand alone. They formed power pools and then the pools evolved into organized, competitive markets. The southern states consolidated differently. The multiplicity of companies in the Midwest perhaps should not be reduced to just a few, but seek consultation through the operational consolidation of an RTO. There is not much consolidation yet in the western states, which you could consider as a supply area. California will always be energy-dependent and seems to be a natural fit for more consolidation. I think the western states will come up with a more organized, tighter regional market. The country should consolidate to a few control areas -- probably these RTOs.