Harvard Electricity Policy Group
Thirty-First Plenary Session

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RAPPORTEUR'S SUMMARY*

Session One: Too Much Money

Price volatility in electricity can have severe consequences for the economy, for growth and development, for quality of life, and for the pocketbooks of consumers. Therefore, it is hardly surprising that consumers and the politicians they elect are not prepared to sit by silently when prices escalate in any significant way. Electric customers have every little appetite for high-priced electricity. Inevitably there will be allegations of abusive/manipulative behavior in the marketplace, excessive profit taking and multiple violations of rules and laws. Regulatory agencies will come under heavy pressure to conduct thorough investigations and to take remedial measures in the form of price mitigation, penalties, refunds, nullifying contracts, etc. The California experience has clearly demonstrated the phenomenon. Real misbehavior requires corrective action. Investigations to ascertain the accuracy of allegations appear unavoidable. The question however, is the frequency, intensity and predictability of regulatory intervention. To what extent and how often will rules require adjustment? How will misbehavior be evaluated and dealt with? Are there lessons learned from recent experience that competitive electricity markets will sort themselves out without severe damage to investor or consumer confidence? Alternatively, is intervention to reduce prices an inevitable and permanent feature of the landscape? How does this augur for symmetry in the marketplace? Is the upside potential for suppliers inherently limited or capped by political/regulatory reality, imperfect rules or bad deeds? Is this the lower of cost or market regulation reborn?

Speaker One

Prices were down in all of PJM's markets last year, not because someone had intervened to force them down, but simply because of supply and demand. Looking at PJM's history, prices rose significantly in 1999, the first year of markets, went down, up and down. In other words, PJM has cycles. And across the range of the cycles, PJM sees prices behaving systematically under its market rules.

*HEPG sessions are off the record. The Rapporteur's Summary captures the ideas of the session without identifying the speakers.

The key result on the generator side is profitability. Not surprisingly, prices had real results for generators; they can under- and over-recover. Cycles also have impacts upon what is built. Generators and investors respond to price signals by building or not building new generation. Although PJM's queues have been relatively full, they are starting to tail off. One response to lower prices since 1999-2000 has been a reduced potential investment in generation.

Having looked at deals, investments and units, I have some questions about the level of due diligence that was done, in terms of both market rules and the actual physical asset. Some generators and investors appeared to believe that when they capitalized the asset price, they would have the ability to exercise market power in the future.

I think the customer side had unrealistic expectations about what competition would produce. It is not the case that competition automatically produces lower prices. It should be no surprise to anyone that prices have been high and low and will be high again.

PJM's rule changes in 1999 and 2000 occurred during periods of high prices, but were not a direct response to the prices, not were they inappropriate interventions. During high demand, when people manipulated operating reserves that resulted in payments of more than $1000 per MW hour, PJM modified its rule to address that situation. When there were very high capacity market prices in 2000, some people said there was something wrong in the capacity markets. In fact, this was an expected result that reflected underlying supply and demand fundamentals. PJM, appropriately, took no action.

The year 2001, however, was a different matter. When PJM discovered that one participant was exercising market power, it changed the rules going forward. The rule change was a result of a particular exercise of market power, and an appropriate intervention, not something that was simply driven by high prices.

Nonetheless, there is pressure when prices are high to reduce them. This pressure is often related to the capacity market. There have been many calls to simply eliminate it, since price is primarily comprised of energy prices and capacity market. If you can take one piece out that you have to pay, that effectively reduces the price.

Recall that in PJM's early years – 1999 and 2000 – most retail customers were not paying, and still do not pay, wholesale prices. As a result they had no direct interest in doing anything about prices. However, LSEs did, and they had to pay the capacity market prices in order to gain load.

The year 2002 was probably the cyclical low to date in both energy market and capacity market prices. They occurred to together, resulting in very low profits to generators. PJM is taking several actions to address these issues, including the overall issue of market risk, stemming from the urgency of the requests from some of the participants, but not as a direct response to lower prices. One action is local market power mitigation. There has been pressure from the generators' side to redesign the capacity market to reduce exposure to market risk and increase the stable revenue sources.

I do not believe that PJM or its members have taken any actions that were interventions designed to increase prices. There have been some proposed interventions to increase prices and net revenues. Generators are taking both appropriate and some inappropriate actions to limit the role of DSM. Given that reliability is a concern, having market prices go down and generators threatening a lack of investment or withdrawing investment is a scary prospect for some state regulators.

In conclusion, the demand for market interventions is driven by cycles that go both ways. I think it serves everyone's interest to understand that this will occur and to be ready for it. We should make sure that the response continues to focus on good market design; we should limit market power and we should ensure that prices reflect market conditions. With a good design, you do not have to intervene wildly to try to either raise or increase prices as you move along. The market will go up and down, but we want the design to last.

Speaker Two

California found out that many really smart people could be very wrong. Consumers and their representatives simply will not tolerate prolonged periods of very high electricity prices. When the first wave of the California crisis hit in San Diego, after just a few months, the demand for intervention was so strong that the state legislature put a limit on retail prices in that area. Of course, they could not control the wholesale prices, or they would have.

We also learned that state policymakers know that they will be held accountable, whether or not they are really responsible. Not letting it happen again is the lesson for people in state government. The politicians must have some levers at their control. In California, we are seeing an effort to reassert some policy control over the industry. Whether good moves or bad, the policymakers want to have some freedom to control the future.

The western US is heavily dependent upon hydro. I do not know if it is true that LMP does not work in a hydro-based system, but I think prices do behave differently where you are not capacity constrained as much as you are energy constrained. Shortages can occur unpredictably and then may not reoccur for a long time. Who wants to be the owner of hydro plants that will be needed only in the one or two dry years in each decade? Energy prices alone will not be enough to keep the existing old oil- and gas-fired units around while you wait for the dry year to show up.

California is now focusing on having an adequate reserve margin, but it has direct leverage only over the IOUs. Probably 25 percent of the munis historically have generally maintained adequate reserves. In theory, the state has some control there, but in reality, the munis are quite independent. The concern is that putting requirements only on the IOUs may create a free rider problem. There is still a limited amount of retail competition in California but the PUC lacks any authority over ESCOs or retail competitors.

Initiatives underway to ensure resource adequacy include an aggressive policy for renewables; strong support for new, clean, efficient natural gas-fired plants; an aggressive energy conservation program; and pilot programs for dynamic pricing. But are we simply creating the next round of stranded costs by pursuing every possible way to get more resources? Can new plants be financed without long-term contracts? Maybe they can in other places, but certainly not in California for quite some time, if ever again. There is no track record yet on whether California's IRP process will work.

I think that there is no belief remaining – in California at least – that the market will simply provide the right amount of capacity. State officials understand that they will be held accountable if resources are not adequate, and prices rise. Reopening retail competition is a problem if customers move back and forth and none of the suppliers is in a position to contract long to get the new resources needed by the system. Investors require a secure revenue stream.

Currently, both sides of the debate in the state legislature argue that their approach will ensure new investment. Those who want to close down retail competition say this will give the utilities a secure customer base that can then be used to contract long and build new plants. Retail competition's advocates say that the ESCOS will build the new resources.

I think that cost-of-service is a popular viewpoint in consumer circles. Efficient spot markets are good, but no one wants to be stuck there when they produce high prices. California does not have many wholesale sellers, so there tends to be an ability for any of the large suppliers to have an impact on the price when the market gets tight.

The bottom line is that consumers are angry and do not trust anybody to have the answers. Some days, they do not even trust the consumer advocates. We have a challenge to regain the confidence of the public that any of us who work in the industry really know what we are doing.

Speaker Three

I spent thirteen months heading FERC's investigation into manipulation in the western markets. High prices that became unacceptable to real people who pay the bills is why the west-wide investigation was launched and we need to avoid doing it again. Do we need to be prepared to do it? Do we need to have the resolve? Absolutely. But this is not the way to regulate.

We had the most sweeping market investigation FERC has ever done. We produced a 400-page report with over thirty generic and company-specific recommendations. Some will change the way gas and electricity will be traded and reported for a long time. FERC looked at gas, electric, physical, financial, jurisdictional and non-jurisdictional, and even at reporting agencies. It was a massive, time-intensive, expensive and disruptive process.

Truthfully, by the time you launch one of these investigations, the time for the most constructive action has probably passed. The lid has been blown off and you are doing damage control. Will something constructive come from it? Yes, but there is a big price to pay when you do it retrospectively.

After going through this, if cost-of-service failed us, then light-handed, market-based regulation failed us even more. From a regulator's standpoint, I now see what I think customers want of us. By customers I mean your father, my father, your mother, a cousin: ultimately, we answer to them. They will not tolerate sustained high prices. There is a huge amount of distrust in the marketplace right now, and even in FERC's ability to deal with it.

We have been in a deregulation or re-regulation process for a decade. We have talked to our customers about price signals and scarcity, and about all of the points that they need to understand to create good infrastructure. For the most part, they hate price instability and volatility. They do not like shortages. They view electricity as a God-given right, as essential to their life. It is not substitutable. These are some of the facts of life that I think the western experience has only made worse.

Going forward, customers need to know that we will act and that we will not wait. They need to understand what we will do. Confidence in the markets will require that we keep things straightforward so that customers can see what we do and understand what we have done. We ought to stay out of the boom-and-bust price cycle as much as we can. I think price stability is not at all inconsistent with price signals and infrastructure. We need a balance between volatility and spot markets and long-term price stability for customers.

I know that a western-markets type of investigation might happen again. I think it should be used as a last resort. If we do not restore some confidence this way, every price will be met with suspicion and it will be a high-maintenance process at the very least, to explain that the spikes are legitimate

Speaker Four

When prices are significantly higher than people expected, there are several explanations. It could be a transitory or sustained shortage; a flawed market; gaming; or regular market power. The policy prescription is radically different in those circumstances. I think one of a market monitor's primary functions is to accurately and objectively distinguish between high prices due to fundamentals, and high prices due to flaws or market power. Equally important, lower-than-expected price signals could be the result of fundamentals or market design flaws, The most notable of which is the inability of the SMD markets to reliably reflect storage conditions. The primary reason for that is that the economic relationship between operating reserves and energy is not well defined in the pricing algorithms. In other words, when you meet your energy demand by not meeting your operating reserve demand, the value of energy has to be equal to the value of the reserves that you are not holding. In the eastern markets that value is $1,000 by definition because that is where we set the bid count.

It is beneficial and perhaps even necessary if you intervene because there is a market power problem or a design flaw. However, it is destructive if you are intervening just to manage the price signal. We need to understand that one of the biggest reasons we are deregulating is that we imagine that markets will guide long-term investment, retirement and forward contracting decisions. We will miss a very important point if we do not recognize that the policy actions we take can undermine the effective market signals in guiding those decisions.

As a policy-maker – no matter your good intentions -- in the long run you end up costing consumers more in intervening to manage the signal when prices become higher than expected. The assets in which investments are made are long-lived. People will heavily discount the future revenues that can be expected from the markets where there is intervention to change market rules to manage the price signals. As an example, capacity markets guide investment decisions by providing long-term price signals in combination with shortage pricing. If investors see capacity markets whose rules are being changed every two years, the ability of the revenues being generated to efficiently guide investments is greatly compromised. Investors do not respond to a market that will cost them a lot of money.

We must clearly separate market intervention that is designed to mitigate market power, which is an artificial increase in prices and market signals that is not driven by fundamentals; market intervention designed to correct design flaws; and market intervention whose primary intent is to manage prices. Differentiating between market power and scarcity can be done as long as you focus on withholding. The primary evidence that the market signal is genuine is that when prices are high and resources are being utilized fully, they are not being withheld either physically or economically.

One caveat is that some of the markets are set up so that if you see the pricing inefficiencies in shortage conditions, one means to achieve efficient prices is for generators to raise their bids under true shortage conditions. This is where you really have a problem with the intermingling of scarcity pricing and market power. With provisions like a demand curve for operating reserve, you no longer have to rely on generators raising their bids to achieve efficient scarcity pricing. Therefore, the risk that the mitigation measures will hinder scarcity pricing is greatly reduced.

FERC has essentially gotten market power mitigation right by focusing on locational market power. Every operating ISO has some form of market power mitigation to deal with locational market power because it is a form of market power that is relatively extreme when it occurs. Mitigating when it occurs allows the markets to operate without mitigation in other hours.

Area forward contracting is germane to the scenario of too much money, particularly in areas with that have experienced large divestitures of generation, because LSEs rely far too much on spot purchases. And there is a natural incentive for LSEs to rely more on spot markets, particularly if there are pass-through provisions in the regulations. If LSEs were more heavily invested in forward contracts, the periods of shortage that result in high spot prices would have less effect. In addition, contracts would be available to finance new generation and to provide a more stable investment pattern. I think there is an implicit incentive to rely on spot markets if you think that policymakers will jump in relatively quickly during periods of shortage. To the extent that supply is in forward contracts, it reduces incentives to withhold from the spot market to cause prices to rise.

Behavioral mitigation should follow a few principles. It should not affect any generator that is behaving competitively, nor should it artificially limit price movements. Ask the question: "Does the conduct I am detecting, whether or not it looks like withholding, affect the market outcomes?" The tests must be very clear.

In every hour of every day, some conduct exceeds your conduct screens. In the absence of transmission constraints that isolate relatively small areas, we find that the conduct almost never affects the market outcomes. The fact that you see it persistently is a good indication that it is actually not an attempt to exercise market power. In fact, it does not meet the basic definition of market power.

In most of the mitigation in place, whether or not it uses the conduct impact threshold, the primary mitigation measure is a unit-specific bid cap that prevents a supplier whose resources are necessary from raising its bid above competitive levels; allows the supplier to be paid the market clearing price; does not affect how that price is calculated; has no effect on prices being efficiently arbitraged between a market with mitigation and an adjacent market.

I think this mitigation measure is the most consistent with the LMP approach because it does not artificially override the pricing algorithms in the market. Unless you tell people that somebody was mitigated, there is no visible sign that mitigation occurred. It is the primary justified approach to the "too much money" scenario. I encourage policymakers to resist management of prices in other cases where it can be shown that the prices are justified on fundamentals.

Discussion

Question: Is a design flaw something that is written into an ISO's set of rules, or an outcome that fails to meet the expectations of what we think the market should be?

Response: Flaws fall into two areas: rules that by definition produce an inefficient outcome, such as the scarcity pricing issue, and rules that distort participants' incentives. Design a rule that sends a perverse incentive and the markets work because we expect participants to act in their own best interests to maximize their profits. In many cases, it will look like market power or withholding. A rule that creates tremendous risk is an example. People are either unwilling to participate or to raise their bid.

Question: Do you suggest that promoting transmission investment in and of itself is a structural remedy to market power? Do you mean regulated investment generally, or just transmission?

Response: It is a structural remedy in the sense that the primary source of market power is transmission constraints that isolate a given area in which a pivotal supplier's resources are needed to resolve the constraint. Upgrading transmission will reduce that kind of market power. To allow an efficient market response to the locational pricing wheels that we have created, people other than LSEs must be willing to put money on the table for an upgrade for a new line or to upgrade a piece of equipment owned by an LSE that increase capability. Simply put, remove the barriers to allowing private investment in transmission. If there are non-economic barriers, it makes sense to also have a role for some regulated investment.

Question: If energy pricing and reserves pricing must be tied, how do they work within a constrained area?

Response: In constrained areas, a big problem is operating with capacity constraints that the markets do not reflect. Reserve requirements in New York City, Connecticut and Boston result in real commitments of generation to protect the reliability in those areas. Shortages occur when you commit the system and there are not enough resources in those areas to hold the reserves dictated by the ISO's reliability rules or practices. Unfortunately, I think we are so short in some of these areas that implementing a reserve requirement cold turkey would be too much for people to handle. New York's second-best solution is its locational ICAP provisions. Some of these areas may have many competitors. The optimal bidding strategy may not be raising prices by your fixed costs because you may be the one who does not run, while everyone else is dispatched.

Response: Generators would like a guarantee of one hundred percent of fixed costs during the year. Part of the reason that generators even in load pockets did not do well in 2002 was because the market was down. Units that are frequently cost-capped did better because they always receive the higher of market price or their cap: they get a margin when they run cost-capped. The plants are better off as long as there are no environmental limits on them.

Question: For political reasons, everyone assumes that there will be price caps of some sort in the system. If you shave the peaks and have a mechanism for filling the valleys as well, what problems do you anticipate?

Response: Forward contracting hedges your costs, gives customers a stable price, gives suppliers a stable revenue stream and leaves a spot market functioning for a residual amount of load. It takes out the boom-bust cycle. I think we need to look at products from general hedging and peaking power to installed capacity to fill the valleys.

Response: Regulators use the four disciplines of law, economics, accounting and engineering. We saw flaws in the west that made this boom- bust cycle what it was and it scarred people across the country. I saw enough price caps for a lifetime. I do not want to see any more.

Question: Is the whole venture hopeless in the sense that in the end, the political system just cannot stand it? I argue that it is likely that almost any place will get strained. Whether the strains and stresses turn out to be as bad as they were in 2000 is another matter. The alternative is to prevent the people who cannot live in the marketplace from going to it. Give everyone else the option to voluntarily contract, but do not mandate that they do it. When things go bad, the people who did not contract will be unhappy. High and visible spot prices could possibly be sustained for a year or so. If that is unsustainable, then restructuring is called into question.

Response: How do you define the people who cannot stand it? Some of the largest industrial customers in Montana who were also the largest employers and the foundation of the economy got absolutely battered. The conversation in California now revolves around core and non-core, much like you have described. California has had a core non-core system for natural gas for 10 or 15 years and the market was very stable for most of that time. Of course in 2000-02 it went the same direction as the electric market and there was some pressure for non-core to get back into core. I believe that because the system was in place for a long time and well understood, it was able to resist that pressure.

Comment: The least-kept secret in the west was a wholesale market in a competitive mode and a retail market with a rate freeze. I cannot think of a more volatile combination. I do not think that your suggestion will work because the west is permanently burned. Rightly or wrongly, people are convinced that prices were manipulated. They do not see the difference between scarcity and manipulation. I think they have some valid points. I do not know how you have scarcity when customers demand a certain amount.

Comment: If we let customers exercise some discretion with demand-side tools, they will use them and the impact will be greater than we have seen. As for Montana, you need to look at the economic development deals made and the relationship and decisions made by the state and the utilities to attract business. But I do not think that when they win, it is okay and when they lose we subsidize them or they threaten to walk away. That is not exactly a pure market. It is very important when you make energy deals, tax cuts or anything else, that everybody understands both sides of the deal.

Question: There is a political or maybe a politicized tendency for regulators to protect customers from the upside risk of prices and in many instances, to lower prices. My sense is that this stems from prudence or cost-recovery procedures that do not yet reflect that supply chains or supply channels have shifted. It reflects demand response programs where customers are paid an extra incentive to shave load in addition to, or rather than, being exposed to market prices. Should the market monitor be concerned about these kinds of institutionalized monopsony?

Response: Absolutely we have to be concerned. Monopsony power can exist in many ways and in many markets. In PJM, there is an overall price cap. It has more to do with substituting for the current absence of active customer participation on the demand side than it does as an effort to lower prices, and I think that has been the primary effect. A market monitor's objective should not be to suppress prices but to create market designs. Let prices reflect the underlying fundamentals of both low and high prices. State regulators can also address the long-term policy prescriptions about the incentives for LSEs. Demand response is a good one. An ISO offers a price to curtail because the utilities lack the incentive in large part. But if they keep the money they save when they have a demand responder curtail, they face would face more efficient incentives.

Comment: Having intermediaries service their function is a way to smooth out wholesale price fluctuations. Institutionally, that is the way to handle the interplay between what could be volatile wholesale markets and what many customers want, which is fixed annual retail rates. If demand resources are the marginal resource, they should set the price, just like generating resources.

Comment: FERC made a decision in PJM to allow large customers already paying the market price to also be paid the incentive. A utility or LSE that charges a fixed retail price but pays the wholesale price has a business incentive to split the difference between customers if it can reduce the wholesale prices. I do not see why it should get the extra incentive if the customer is already paying the market price.

Comment: Offer DSM into the day-ahead market where it acts like anything else and can set the price, and in real-time as well, depending on the type of resource.

Question: Even if emergency resources are brought on?

Response: If the emergency program is brought on and it is a marginal resource and the price says it is $500 that is what the price ought to be.

Question: Some generators feel that they are not receiving the guidance they need from markets about when to take a unit offline or not offer it in real time in circumstances that are not entirely clear. They are often told to read the market rules. How do we provide better information about when units can be held offline?

Response: PJM, for example, has very clear rules and the capacity market rules are a key part. If a capacity resource sells a call option on its unit, it has to offer it day-ahead. It cannot simply withhold. If you are not a capacity resource and your unit is down, you can only sell unforced capacity. Clearly there is an incentive to minimize the amount of forced outages.

Response: The market monitoring plans in the Midwest and east contain the ability to look at the logs or visit a unit. It serves as a deterrent against providing false information.

Comment: We have seen splitting between customer classes in the east, as each state begins to consider what to do as retail access expires. Draft legislation reflects treating large and small customers differently. Large customers are also seeing prices that are more closely tied – daily, monthly or seasonally – than in the past. But in a state like Connecticut, there is no recognition of what is happening in the wholesale market and the politics do not allow the state to address the e economic situation.

Response: In the final analysis, the federal level knows that there are only retail customers. They are the people who ultimately pay the bills. I think different states will make different choices. Somehow, after we get though the process of understanding how federal and state regulations work, customers will choose. Their choices may not always be what we like, but we have to work through that.

Comment: The reality is that we have done a rotten job at the state and federal levels of defining the problem we are trying to solve. Part of the resistance to change is that we have not told people about the consequences of not building transmission or generation or having a demand-side option. We need greater transparency for the RTOs so that state and federal regulators can give a better picture. If we had been alert in terms of looking at infrastructure, we might have avoided some of the problems in the west.

Question: What is necessary in hydro-based systems that may be different?

Response: If shortages will be prolonged when they arise, just handling the situation with short-term prices will not work. There must be a mechanism to provide an ongoing revenue stream to whoever is responsible for the units that you do not often need.

Response: In the Pacific Northwest, hydro's blessing is its curse. It is fuel by God. We should re-rate hydro realistically, based on availability in upcoming seasons, rather than on nameplate or something else that does not make sense for a non-fossil fuel-fired facility.

Comment: There is relatively little about hydro that requires fundamental differences in the way we think about markets. The principal difference is in price mitigation. Price cap rules for LMP in thermal systems for thermal plants obviously do not apply. You need to do something else with these energy-limited systems over a long period.

Question: How can you expect the forward markets to provide the correct price signals if the spot markets are designed in a way that prevents prices from rising, and then the retail customers can then rely on the spot market, rather than going to the forward market? Also, how can you expect LSEs to make forward contracting decisions when they do not know how much their load will be two or three years from now?

Response: I am not talking about protecting people from a defective market structure by letting them be in the spot market; have price spikes; and then giving them a risk-free hedge by dampening those. The worst thing states can do is have people mindlessly in the spot market and benchmarking that.

Comment: I agree that forward contracting will be inefficient if the spot prices that you manage your risks against are inefficient. The demise of the marketing community concerns me because they provided an important intermediary function, facilitated the forward contract market and made it more efficient. Generally, it is a low margin business, but we have to get it back.

Question: How would a 20 percent renewable portfolio standard be maintained during a bad hydro year, absent market-based pricing?

Response: California does not count large hydro as renewable. Small hydro is counted, but the big swings seen in hydro production are not part of the RPS. If you do not meet your percentage in a given year, you can bank one year if you have access and draw that down, or you can be short one year and make it up in another. It is on average over time.

Question: If we can get good market design with the RTO or ISO as the backstop and so on, how long will it take?

Response: From a California perspective the body politic will not accept being dependent on the good graces of FERC to make sure that things work properly. Did FERC drop the ball along the way? With the benefit of hindsight, it probably could have worked more closely with California at certain times. People recognize that FERC must roll up its sleeves and work this through.

Who would be the counterparty to long-term forward contracts? What would be the contractual duration?

Response: The structure of standard offer contracts affects forward contracting because it changes an LSE's incentive. There will also be uncertainty about who serves load in the not too distant future. Maybe we think too simplistically about forward contracting when people need stable markets and contracts that allow them to make decisions in a multi-year context. Maybe you take a long-term position but the load you serve shifts and the ability to unwind becomes important so the prices of the products of various durations into the future can be tighter and more liquid. The last thing I would do is issue a rule saying you must have a portfolio or contracts of a certain percentage.

Question: Some LSEs are beginning to view DSM as a competitor. Some states' DSM funding is being targeted as states come under increasing fiscal pressure.

Response: The fact that generation views DSM as a competitor has led to appropriate and demands for intervention. The upside is that this will lead to better design and more careful thought about how they affect markets.

Response: Some utility filings before PUCs propose additional demand-side efficiency as part of their procurement plans. They would collect money through the procurement costs recovery mechanism to pursue additional efficiency objectives.

Comment: I am concerned that there is still no viable working market for medium and small customers. What repercussions does this have for the wholesale market, or is it only a political question?

Response: The fact that a retail customer sees a flat rate is not inconsistent with retail competition. Although everyone talks about DSM, the little we have has been forced. Obviously, if end-use customers do not see the price in real time, they cannot react, and even if they did, they would not benefit form reacting in real time. Metering of course is a partial solution.

Comment: If an LSE is on the hook to pay the wholesale price and serve the customer, it does not matter what the end-use retail rate structure looks like. Still, someone bears the risk and must hedge it. If you do not have retail meters, you have to guess the load.

Comment: We are interested in working through market power mitigation in California but we cannot seem to get the state to pay any attention to it.

Comment: Better communication is always necessary. There is no reluctance at CAISO to move forward with MD 02, but the very adverse political reaction has forced the ISO to slow down.

Comment: The potential solution to some of the wholesale market problems or the desire of politicians or policymakers for more rate stability is long-term contracting. Default service procurements of six months to one year do not get you much hedging.

Session Two. Too Little Money

If prices dip too low, or if the potential for profit is effectively capped at a less than compensatory level, or there is no effective floor to potential loses, investors will be loathe to risk their capital. The likely results are shortages and more price volatility. One vehicle for addressing this problem is hedging. Hedge markets in electricity, like trading, have proven remarkably volatile and vulnerable. Many potential market participants have become reluctant to participate. As a result, more structure administrative ICAP markets have been *proposed to provide a more predictable form of hedging. Critics have suggested that some, if not all, of the ICAP and resource adequacy proposals are not market mechanisms at all, but a form of subsidy to suppliers to entice new investment in capacity. Well-designed and well-functioning energy markets, they contend, do not require such mechanisms. Supporters of ICAPs say that such market vehicles recognize the value of having installed capacity and effectively allow investors to avoid the risks of relying exclusively on energy markets. They provide consumers with grater reliability, particularly when linked to resource adequacy requirements. To what degree do ICAP markets and resource adequacy requirements add value for investors and consumers? Are there design elements in ICAP proposals that cross the line from market mechanisms to subsidies? Do ICAPs, and the various elements within them, help to resolve the difficulties of enticing new investment in an efficient way, or do they add inefficiencies? How can CIAP be made compatible with the fundamental objectives of electricity restructuring?*

Speaker One

Resource adequacy is a reliability product to enable suppliers to recover a portion of their fixed cost. New York requires it, and the New York State Reliability Council, an independent agency, sets the level of resources and establishes a reserve margin. Typically, it has been 18 percent, or 118 percent of the forecast load for the last several years, and it is in that order of magnitude. There is a fixed number set and LSEs are expected to pay for it each year.

On the other hand, the energy market is where generators, suppliers and resources would be expected to recover or make some profit and recover their variable costs. Of course the revenue and ancillary markets were designed to allow resources to recover their lost opportunity costs when they are not supplying energy. The supplier's revenue stream is the total of the three markets. Each has a specific purpose. Depending on the type of resources, they cross over in some areas.

The council sets the ICAP requirements a year in advance. LSEs can recover their cots self-supply, bilateral, or auctions conducted by the ISO. There are six-month strip auctions, monthly auctions and a deficiency or spot market auction. The problem, by no means unique to New York, is that resources have tended to exceed the requirements by any level and prices are lower than what it would cost to sustain new resources or to encourage them to enter the market.

New York is somewhat dependent on external resources. When they did not come to the table in 2000-2001, the market appeared to be on the short side and prices were fairly high. Since then, resources have been built and with excess supply, now prices have dropped off.

In May 2002, the New York Public Service Commission and other stakeholders proposed to resolve the resources problem and filed a demand curve filing. In May 2003 FERC approved the filing with only a few changes and New York is now applying it.

The demand curve offers an alternative to the ICAP market by giving a value to resources above the minimum requirement and a value with a declining price. It is intended to reduce the price volatility inherent in a vertical demand market. That is a fixed ICAP requirement where anything short of that requirement results in deficiency prices and anything above leads to very low prices. A gradually declining demand curve is still intended to ensure a competitive, fair, non-discriminatory market. Any resource can play in this market, under the same capacity rules used in PJM and New England.

The demand curve applies only to the spot market auction, which is the last held before a capability period or an obligation procurement period. New York's obligation procurement periods are monthly. It will continue to conduct monthly auctions and strip auctions to allow people to buy in a traditional auction mode. You can buy capacity six months at a time or one month at a time, and if you do not buy enough capacity to meet your requirements and there are extra supplies over and above the requirements, you will compete and participate in a spot market auction using the demand curve.

All LSEs will participate in the spot market auction. On a monthly basis they submit their capacity, certify that they bought and that they have a minimum requirement. The auction determines their total obligation: that is, the excess capacity or extra capacity that would be available at a lower price will be allocated to each of the LSEs in accordance with the spot market auction. The auction clears where supply and demand meet, except that this time, the demand curve is a sloping curve.

Capacity in upstate New York costs about $85 per kW year. It is the straight fixed cost of installation. New York city is $159 and Long Island is $139. Those numbers probably range to $180, depending on what you look at. It has been determined that the curve will allow up to 112 percent of the requirement for the state. Therefore, in a 118 percent requirement market, about 132 percent of the load would be allowed – in effect, a 32 percent reserve margin. If that were attained, it would be at zero price.

Eighteen percent excess capacity under the demand curve is allowed for New York City and Long Island. The reason is largely an issue of market power. You must have enough excess allowed in the market so that you can allow the next large, baseload-type unit to get in the market. For a 500 MW unit on Long Island, that is only a 4,500 MW market. The generator will be able to sell 400-500 MW at the equivalent of the 400 MW lower price.

After the summer, a consultant will take up to a year to review the numbers so that there is a sense of how the next few capability years will look. The supplemental supply fee will probably not exist. Any loads that are short will probably pay the market-clearing price and New York will attempt to shop for new resources with that price.

In sum, the demand curve offers a balanced approach. The stakeholders and FERC have agreed. It is intended to allow suppliers to recover a portion of their fixed costs. The demand curve actually crosses the requirement at about $56 on an annual basis. This is the compromise among the suppliers, the PSC and the other stakeholders. It recognizes either a phase-in to ameliorate rate impacts, or an offset for energy and ancillary service revenues in the form of profit that could be credited against ICAP.

LSEs will continue to meet their ICAP requirements, either through self-supply or bilateral. As you know, the near-term fixed requirements in the current market design, especially with a monthly market, have led to volatile price swings, no clear long-term signals and no risk, and it is difficult to finance projects. New York will continue to work with New England and PJM in the Resource Adequacy Model Group. It will continue to study two- or three-year and longer annual markets to send even better longer-term price signals.

Speaker Two

I will focus on the policy options for assuring adequate capacity, looking at the reserve requirement system versus an energy-only pricing system, and the market performance in the northeast ISOs. In 2001 and 2002, spot prices in each of the ISOs were below the cost of entry, despite real scarcity events in each market, extreme weather, very tight reserve margins and a need for new entry. The capacity market revenues were insufficient to make up the difference. The implications are that these markets have not been infected with market power. If they were workably competitive and needed new entry, we would expect spot energy prices to be significantly above the cost of energy during those two years. As a matter of economics, if a market needs new entry and has prices below the cost of entry, I think that market does not need significantly more mitigation. A loss of investor confidence in the business of energy supply being able to recover its cost certainly bodes poorly for the long term. And it is important for the ISOs to implement pricing rules that do not suppress prices.

In terms of market mitigation, if you want a market that does not rely on these types of capacity markets, you have to ask whether a thousand-dollar bid cap may be too low. There are times when generators have cost of supplies greater than a thousand dollars for emergency output. There are loads that might curtail for more than a thousand dollars per MW hour for brief periods. The value of lost load is probably higher than a thousand dollars. Perhaps automatic mitigation may not be justified except in load pockets. If you solve the scarcity pricing issues, it may be less important that you have these mitigation measures in place.

You could have a competitive market without capacity payments, but it would require a far greater tolerance of price spikes and high spot prices and less aggressive mitigation. The political will to support such high prices is demonstrably absent. The capacity markets in the northeast have been designed poorly, and I think most ISOs have been uncomfortable with how they have actually worked.

These days the entrant unit is a state-of-the-art combined cycle. Would it have made money against the 2000, 2001 and 2002 spot prices? The levelized entry cost to build these units is $115. In New England the units are making $61-76 per kW year; in New York $74-78 and in PJM much lower. Despite tight reserves and scarcity, the energy prices alone did not compensate the new units, nor if we add in capacity payments, if you look at the historical spot capacity market prices.

The basic capacity market problem is ensuring that market clearance always occurs. Unlike the regulated market, players in the competitive market rely on market prices to provide enough compensation to entrants to recover their costs. The two policy options are: first, a reserve requirement system that will maintain sufficient excess capacity to ensure that the market will always clear even if the demand curve is vertical, and second, sufficient price response of demand so that the market clears even if the supply curve is vertical.

For generators to stay open under these two systems, they need to recover their variable costs and their avoidable fixed operating costs. The idea in the energy-only system is that market-based energy-only prices lead to economically efficient capacity levels in the long run if prices are allowed to rise high enough to clear the market. Customers would rather curtail their use of power voluntarily than pay very high energy rates. The competitive market will result in a market-determined level of reliability. When there are high prices, price-responsive demand and operating reserves, an administratively determined reserve requirement is not needed because the market would always clear.

The political barriers are obvious. I think the technical barriers are solvable in the long term, although in the transition, there may be inadequate levels of dispatchable demand and real-time metering. The alternative approach is the reserve requirement system where capacity is actually a positive externality and owners of capacity and demand response resources provide reliability benefits to the system from which all users benefit. If we only relied on energy prices, we would have a sub-optimal level of reserves in the long run, leading to a more than socially optimal number of blackouts over time. Implicit in this is that if customers could always voluntarily curtail and if they knew the prices in any given hour, then the market should always clear because customers would eventually turn off their use of electricity rather than pay high prices. The alternative justification is that high-enough energy prices are politically infeasible, and an installed reserve requirement is a second-best necessary solution to ensure market clearance.

The system works when the reserve requirement is imposed on all LSEs: each must pay its fair share of the reserves. There are no free riders. Competition among capacity owners will drive down the long-term price of capacity to the price of the last unit that you need to stay open to clear the market, so that sets the market price of capacity. All capacity in the system receives a capacity payment to compensate them for the market-determined capacity price.

The ISO does not administer a capacity market. The act of requiring and enforcing installed reserve requirements and having mandatory reserve requirements creates the market. Whether the ISO holds an auction is not central. It is important that the penalties be high enough so that people will want to invest in the capacity payments.

Two problems are the time frame and retail competition. The latter has driven the northeast's ISOs to have very short-term capacity markets. However, it is unclear that they provide the proper long-term signals, especially if people believe that the payments will not be taken away. The markets have also worked somewhat poorly in part because of the boom/bust nature of the capacity market prices, as well as different flaws in each market. A Joint Capacity Adequacy Group has formed to design a set of principles and a capacity market to address the problems. It plans a filing at FERC by the end of 2003 or early 2004. The solution is a centralized auction in which the ISO actually procures capacity from generators or suppliers. Anyone can choose to self-supply. With enough lead-time, a new generator could participate. The cost of capacity that the ISO procures is charged to the end users through a non-bypassable fee, just like transmission.

A problem with capacity markets is that some of the retail suppliers have done a bad job of purchasing capacity. Then they tell regulators that the markets are flawed, and that they are paying too much and losing money. A lot of political intervention happens in these markets. The new approach has the advantages of self-supply and provides a transparent price of capacity for the regulators, who in the long term must figure out what should be passed through to customers. The winning bidders have an obligation to deliver the capacity with very high penalties for non-performance, creating incentives to ensure obligations are met. There are also ways to have more efficient cost recovery of these payments, a policy choice that regulators can make.

One approach is a fixed annual fee spread over time. Another is an hourly reliability charge that would only be allocated to the hours when the loss of load probability is high. This latter approach would increase incentives for demand response in these markets and allocate the capacity requirement to the users in those hours when the need for capacity really exists and the market is tight. Depending on its design, it could increase incentives for generator availability. You could decide to penalize the generator it is not available on the hour when the capacity price is allocated. When the loss of load probability is high, I do not think it should get the payment. This approach would look much like high prices; of course, you would just be recovering a fixed fee rather than over 8,760 hours of the year for the few hours when the cost of capacity is high.

Speaker Three

My view is from a part of the Midwest that does not yet have capacity markets, but there is debate. It has been said that sustained high prices will not be tolerated, but what does the word, “sustained” mean? After the incidents of less than a week in June 1998 and one day in July 1999, customers and utilities demanded that FERC install price caps. In 1999, the shortage in some areas may have been more than temporary, or it may have been based on incorrect assumptions. After 1998 until 2003, 9000 MW of mostly new merchant build – real available capacity -- was added to the 22 GW load in the Midwest.

In Illinois, which was also undergoing retail access at the same time, as capacity increased, the retail electric suppliers did not buy it. It was not a very stable situation. Then came the price bust. Belatedly, the financial people who were so hot to lend money to project developers to build plants all around the country have found out that they may not get their money back. We can learn from this history that we can tolerate this boom/bust cycle, have pure capitalism and take the consequences. But the consequences of having insufficient electricity as California now knows are devastating to the economy and to health and safety when you have to shed load and people are in elevators in high rises.

The Midwest does not have a mature market. Load response during those summer weeks could have ameliorated the high price. Bid caps limit the ability to recover costs during times of true scarcity. There must be deliverable iron in the ground. It is no good for thousands of extra megawatts to sit in Illinois, pretending that they help out Wisconsin. They cannot even get to Wisconsin on a good day, and on a bad day, they can never get there.

I assert that the midwest is the wrong model. Sure, it had high prices and got the correct response. It thanked FERC for not imposing price caps. However, how does an RTO handle different or no state requirements as discussed in FERC’s SMD NOPR? Wisconsin wants an 18 percent reserve for a year ahead, far in excess of the general Midwest number that is probably on the order of 12-14 percent. How can an RTO operate good energy markets without a requirement that generators bid into the day-ahead market? I think FERC is now at a crossroads in the federalism debate about the power of the states when there is a regional market. I think FERC tries to take a midway point in talking about regional state committees. That is fine until the question of who will pay for the extra capacity in state A is discussed by the regulators in states B, C and D.

In the end, the obligation must be on the LSEs because they have said, “We will provide reliable service to you, our customers.” In a market, everyone must play by the same rules. It should not be a huge gift to people who have made mistakes. It is like insurance because we do not want to end up with the situation we have now. I think that is what history tells us.

Speaker Four

For a generator, there is always too little money. As a generator, until we know the market design for the future, we cannot spend much time on new development. Right now, there is little commitment to long-term contracts and the important collateral requirements needed by generators to move forward. There is too little commitment in the area of RFPs from creditworthy entities in which generators would like to participate. Even though we like to think that generation is important, if you do not get the returns, it will not get the money. And there may be too little commitment to standardized rules that all can follow, and trust in the regulatory structures and schemes in several places.

One western state requires that the utilities within it that issue RFPs for new capacity have a clause stating that contracts entered into can be modified or abrogated if the supplier has ever been accused, not actually convicted, of having dirty hands in terms of some of the market manipulation. Who would bid into that state? But the situation is so dire now that people are trying to rid themselves of assets that are on the ground or halfway on the ground. In the southwest, there are no commitments for 2006.

Going forward, can we rely on all-energy markets? If I want to bring in new capacity, there is a higher hurdle rate because my weighted average cost of capital has gone up. We do not look at that when debating market design, but it is the reality when finding money for new plants.

Some states have lengthy licensing processes of at least two years. It took 22 months in California and 11 in Arizona – for the same facility. Once you have the permit, you have created a option that can be as small as 18 months. In many instances, the people who spend the money to give you the option are gone in 18 months because of the rules in various states. When discussing market design, how do we keep the options alive so that the states and investors have the ability to build when needed? The time for the permit is critical because the longer you have, the more money you put out and the fewer number of people willing to invest if a project takes forever to build.

I think we have a "deer in the headlights" scenario, where the generators are the deer that have stopped cold because they are trying to clean up the mess on hand. They are not looking forward and there is no incentive for long-term contracts. The states are also trying to clean up the mess and are thinking only about the next 12-24 months – generally the timeframe that regulators are in office.

We need to move portfolio guidance out in a longer term. You can still bid and receive very good prices, but you have to give people an opportunity to make some money back before they are willing to commit. I would not commit to a new facility without a five-year contract at a minimum; 7-10 would be better. My five-year price will be higher than the price I would give for the 10-year contract.

Are ICAPS efficient mechanisms in committing to future capacity? When I assemble a pro forma for a new plant, I discount the ICAP because we do not have much history with it and therefore cannot really rely on it. Do I put this risk mitigation measure in the pro forma to get me over the hump to commit to something, or is it merely a supplement that tells management there is some upside after we get to the hurdle rate? I do not believe an ICAP would convince me to build a new generating facility; at this time, it is difficult to value some of the ancillary services. ICAPS do a good job of keeping old, inefficient facilities on board, giving us a reserve margin. But when do we retire or replace the facilities?

In the generating business, it is often location, location, location. Now it is contracts, contracts, contracts. How much are you willing to commit to, and for how long? Convincing management to do a merchant plant, when we are fully contracted on 85% of our capacity for about a decade is difficult.

Speaker Five

We hear that electricity is too volatile, that we will end up with under-investment and shortages that we can correct simply by instituting an ICAP market. However, the best cure for high prices is high prices and we have seen it in every industry. Electricity is not that different. Treat it like any other financial commodity.

In the ICAP debate, I wonder what capacity is? Because we are a credit-worthy counterparty, people come to us to obtain financing. There are four types of contracts that transfer value of some sort. The first is the right to export energy. The second is a primary right to power during a market failure event, if you cannot buy or sell, no matter what the price. It is administratively complex; you cannot readily curtail supply to the people who do not have capacity. Capacity is an ex post question, not something that you can use to manage the system. The third type conveys the right to avoid a deficiency fee – an obligation that gets on a retailer. This is difficult to trade and to hedge, and an inefficient mode of creating the incentive to build. The fourth is the right to purchase energy at a fixed price.

The problem with a regulated capacity market is that it is under the control of politically motivated entities. If you are a trader without any capacity, will you try to put it in the long or the short side of your book? The politicians will be happy to let the prices go down. Generally, traders tend to bet against this deficiency-charge-based capacity market, with the result that you have a backward-dated market. In other words, forward prices tend to decline over time and it is a very short-term market. It is an inefficient way to encourage new investment because you cannot fool the banks a second time. Because you cannot hedge the forward market, it becomes a costly method to incentivize new investment. It also is a bit of windfall for incumbents and does not really help people who want to develop. A capacity-based market encourages over-investment in combined cycle and less investment in peaking plants. Finally, there is the inevitable boom-bust cycle.

Discussion

Comment: I have thought that ICAP markets would fall of their own weight, but so far they have not gone away. They are problematic because we will have an inefficient or sub-optimal generation mix. What occurs de facto is that the ISO becomes the new integrated utility running the integrated resource plan because no one can make investments without receiving approval for their capacity component in the ICAP system. This is a fundamental threat to the electricity restructuring that we started with.

Response: I thought that the price of capacity would go to zero and there would be no market. But nothing was being built. We treat a demand response or customer as if they are resources. The contribution to the obligation is sold back to the ISO as a capacity product and measured identically to a generator in terms of ICAP. Customers willing to contribute to reducing the load receive a resource value; an intermittent receives a certain value; and a generator receives a certain value. They are paid for megawatts of UCAP based on performance and availability, not on total iron in the ground.

Response: If the ISO runs a forward auction, any resource can bid if it thinks that through energy and capacity prices, it can build a resource or be available. Marketers can also take on this obligation. The caveat is that if you allocate the amount that the ISO owes generators to the hours when the loss of load probability is high you do not receive the payment. You just have an ICAP requirement and the generators have to be there.

Response: Like squeezing a balloon, a bulge will pop out somewhere else when you push on it. When there is no cap, why do you need administrators to determine who ran and who must be paid?

Comment: If we did not have caps, we would not need capacity markets.

Response: Other than getting the transmission pricing right so that the parties that must pay for the generation fix face an economic decision on a balanced playing field with transmission, having no price caps or bid caps is unacceptable politically.

Comment: Transmission versus generation is more of an argument between the regulated and competitive constructs because the problem is that no one wants to build transmission because they are unsure if they can recover their investment. At least a generator has mechanisms to do so. An ICAP market ensures there will be enough capacity next month, next year or in the future. If you penalize someone for not being there after the fact, it is too late. Generators do not have an option to opt out on their own in an ICAP market. If they trip or are forced out, they will receive a UCAP penalty of a D rating and those go forward.

Question: Do long-term contracts obligate customers to be bound by long-term decisions that may not be cost-effective into the future?

Response: Why not regulate a retail provider the way we regulate a bank? Require it to duration-match its portfolio according to its expectations of the duration. We do not allow banks to have a huge mismatch and speculate in the forward interest markets. You could still play the market a little from the short side on a delta basis. The wholesale market could float freely against that because the retail suppliers would have contracts that protect them.

Question: Is it an obligation for an ISO or the LSEs?

Response: It is more the LSEs. That is the way that regulators or auditors look at banks. If the regulators go to transition, they must make the rules clear, establish he dates, establish the percentages that will change yearly so everyone knows how to play and stick with it until we get to an endpoint.

Comment: A developer comes to an intermediary like a Morgan Stanley for a long-term contract. That does not mean the financier must match that long-term contract by an equal long-term off-take with the retail provider. Many developers of larger facilities will require longer-term contracts so they have some certainty to getting back a decent amount of their investment: not necessarily a life-of-plant contract, but it must be longer than the years when you are in the development phase.

Question: Is the thought that the output would not be sold to someone?

Response: The output could always be sold but if the price is uncertain or unknown and you have only the first two or three years identified, long-term financing for new generation will be difficult to find. It depends on your willingness to take risks and the amount of money that will be put toward the facility. You look at risk differently when investing 50 million instead of 350 million.

Question: If a state regulatory commission requires longer-term contracts, does the risk go to the ratepayers?

Response: Yes, but they can always unwind them later if they go into a deregulated situation or make a mark-to-market on them, essentially relieving the obligations.

Question: Do you mean a load entering into a long-term contract with a supplier? You should be able to resell your capacity if it is a capacity contract or an energy and capacity contract backed by ICAP if you end up long or short.

Response: The general truism in almost all commodity markets is that a long-term contract on the supply side is more important and longer-term than a long-term contract on the demand side. Your regulation would be designed to facilitate the financial wherewithal of the retail provider. A classic example is that San Diego Gas and Electric would have been better with a one-year contract. Just because you expect to keep a customer for 20 years does not mean that you should enter into a 20-yeara contract. Pitch your duration the same way, for example, that airlines hedge their fuel risk. They do not buy fuel for the life of the plane.

Comment: That seems to put the risk back to the supplier.

Response: In a functioning market, you can always buy and sell: it is just a question of price. When the forward prices signal the need for new capacity, people will enter into long-term contracts and finance plants with them. But that does not mean that there must be long-term contracts of equal duration on the other side of the equation in selling to customers.

Comment: It is true that price spikes stimulate supply development or generate development. But if the price spikes have market power and you don't know that, you will over-commit to generation. Maybe that has happened in some of the markets.

Response: I do not think there was market power in 1998 in the Midwest. I think it was a temporary scarcity caused by poor performance of nuclear plants, a few tornadoes and so forth.

Comment: Yes, there was some scarcity, but I cannot tell you there was no market power in that price.

Comment: I think the developers misread how robust the scarcity was, after the fact, and they all went after the market. Many have been punished which is one of the hard learning lessons. Another is that industry and the banks will not go through that again.

Comment: I agree that people on the generation side made bad decisions, but there is also a policy question about how to structure the market. Either you allow prices to be high or you have a reserve requirement that is mandatory on load. If you do need new entry, the competitive market must send signals in the long run when it is needed, and the money has to be there.

Comment: There is another choice: move the prices up in the real-time market when there is a true scarcity, but not by allowing generators to bid significantly above their costs.

Response: No one talks about whether $1000 a megawatt is the right choice or the value of lost load and how you get that done. I would like to see the ISOs begin doing it.

Comment: If there is an ICAP market with price caps and rules that different markets put in place; and we get in the IRP business where the ISO does long-term contracts under a plan that builds in transmission and renewables, have we returned to ten years ago? Rather than have the ISO do the IRP and the contracts, California will wind up with the regulated utilities that they can control doing that. We will have long-term contract and a reserve margin that is billed out or charged to other ESPs if you have retail competition. It might be that the competitive market structure we envisioned dies of its own weight, not the ICAP market. How do the rating agencies look at PPAs in the context of long-term contracts?

Response: I do not know if the outcome will lead us back toward utilities doing their own generation. That would be a blow to deregulation and consumer markets in the future. A utility could ask its regulator to approve something and then tell the rating agency that it is not really very risky.

Response: The margining requirements that exist on commodity contracts are a large part of the problem. If someone sells us the output of a plant in today's low-priced environment, we would ask them to post that amount in cash or something readily convertible if market prices did rise in the future. I think that is the liquidity issue that the rating agencies look at. I do not know if it is optimal to finance base load plants over 15 or 10 years. Generally, under a cost-of-service-based regulatory environment, utilities tend to over-invest in base load and in high-capital-cost plant. I think that the true risks are not being captured and measured appropriately. The cost of capital for a peaking plant that costs 50 million versus a base load plant that costs 350 million is totally different. How much time and trouble is it worth digging around for market power if it is just one day and an extra thousand dollars? How much power did OPEC wield after it let prices go really high? Ultimately, the cure for high prices will come from the price signal itself.

Question: If you must have a price cap for political purposes – forget about whether it is good economics – do you necessarily end up back in IRP?

Response: You need an ICAP market because there are price caps; because there are political realities; and because there is a reliability requirement in NPCC, NERC or a reliability committee. Once the resources are there, the rest of the market is allowed to work freely and competitively.

Response: As a developer, I do not need an ICAP to support a project if I have a well-functioning bilateral arrangement that I can put in place. Most important is the opportunity to win a bid or win a contracting situation with someone that will support the facility, and I am obligated to build the best in the best location and bring value to that customer. However, many areas do not have a well-functioning bilateral arrangement. Instead, they may have smaller percentages of bilateral contracts. Maybe they need an ICAP to transition to a more fully functioning bilateral market in the future.

Question: If the bilateral contracting arrangements are either insufficient or sufficiently uncertain, does ICAP then become less offensive? Do the views of the rating agencies make ICAP more attractive?

Response: Whatever we have must be a transition mechanism.

Response: In the past if you were the only LSE in a control area and had a true shortage, you did what you had to and dealt with the consequences later, once the system was in a safe condition. Operators are taught to get the system safe and deal with the politics afterward. The problem is more complicated when there are numerous retail suppliers. Whose load will be interrupted? We have accepted that an LOLE of 0.1 day per year is a reasonable standard. But this is now a commons problem. The midwest has until 2010 to figure out what will happen when reserve levels begin to drop. We will sign long-term contracts. But why would you sign them in a competitive environment where you may not bear the consequences of inaction?

Comment: There may be an opportunity to phase out price caps using something like a reserve demand curve so that real-time prices are determined by demand. I think it is impossible to design a functioning ICAP market. If you have a requirement that is fixed and you do not have a sloping demand curve that is not really a market.

Response: Your idea could work in New England because it already has 12,000 MW.

Comment: If you put an ICAP market in New York, you spend 37,000 times $10 a kW month, and much of it goes to the existing generators. Get the spot prices right and you might get the investment more efficiently via the market.

Response: Make the ICAP payments look like energy prices so that they send some of the shortage signals, especially as a transition mechanism.

Comment: What will the level of trust be when people have to put down real money to fund a project? When push comes to shove and prices go up, either in the thousands of dollars for a few days, or the hundreds of dollars for a few months, will people believe that the regulators will not feel the political pressure? When the price of gas goes up, we always hear that somebody is doing something wrong. Will bankers believe that the regulators will be able to weather that kind of political pressure? I would expect that the people responsible for ensuring that load is served want to know the technical basis for changing what has worked well for the US.

Response: In California, we learned the importance of having forward contracting. That knowledge helps people understand that eliminating price caps is not the end of the world. People will only be exposed to the extent they want to be in the spot market.

Comment: I think the issue of trust is key. A way to have trust is to have a few years of a capacity market in the northeast or another region, where you cover the cost of capacity that the ISO bought as a spread-out charge over 100 or 200 hours rather than over the whole year, so it looked like real prices. If the political system cannot stand that, have a transition so that it is a flat fee over the year, and hide the payment a little bit that way. If the political system can stand that, maybe you transition to an energy-only market.

Comment: Although you ca act quickly to change an ICAP market, it is much harder to change fuel oil, gasoline or electricity..

Question: How will we build diverse resources, not just cheap CTs or cheap, gas-fired combined-cycle units? I realize this is a public policy issue, but remember that consumers were promised lower prices, more reliability and creative technology. We have given them higher gas prices to heat their homes and maybe for their electric bills. Does that bother anyone?

Response: At the right time, would we be willing to find a developer for a coal plant or a nuclear plant? I suspect we will. People will make the right decisions because they have to look at the number of years that they are running something.

Comment: If you think that gas will stay high, a coal plant is a good option for LSEs to acquire.

Comment: That coal unit will not look good trying to recover its capital cost over three to five years.

Response: You would not do it on a one, three or five-year contract.

Comment: Evidence is accumulating that things tend to work well if you have an efficient market design in place. Think about your fixes as transition problems and design them accordingly. I have the feeling that we are over-reacting to the problems we have had.

Comment: I have seen these markets get fixed and every time something happens, there is a problem. As a generator, we feel that the political and regulatory processes are somehow stacked against us. We do not hear policymakers say, "Let's revisit a thousand dollars to see if that's the right number" Instead we hear that if there is any single instance of market power, we'd better claw back to the spot prices and do refunds and make sure there is no market power whatsoever, but allow for scarcity pricing – as if they can distinguish.

Question: As the market in the midwest becomes developed, we are nearing the time when we introduce an LMP environment in a very large footprint. If there is a price cap, does that immediately negate or shut down all capital formation, or do the terms become too onerous for new investment? There are still some pockets where investment is critical for generation, and in areas with transmission constraints.

Response: It is a matter of degree. I think the thousand-dollar price cap is too low and will cause shortages. It will impact the bids we show people, as well as the types of contractual cover we will offer power plants.

Response: I think everyone knows that for twenty years, Wisconsin neglected its infrastructure. It needs capacity and has bought it from Illinois. Illinois needs capital formation and to be able to site things in Wisconsin. Of the plants that have been able to get delivery into Wisconsin, the ones that were there early are receiving a higher price than those delivering to the rest of MAIN because there is a shortage. I suppose if someone can actually build a plant in Wisconsin, the capital will be there. I think people have to wake up, as California did, and take care of their own infrastructure.

Response: One of the successes of market design is that there are a lot of vested interests in the areas that have incentives to get something big built. It may also be true that some areas only need upgrades.

Question: I am not convinced that an all-energy market will get your resource adequacy or an adequate reserve margin. By definition, a reserve margin is capacity that is not producing energy. If all that gets paid for is energy delivered, why would anybody build an increment of capacity that will not be used, particularly when it is something like hydro that will be needed only occasionally? If you are a governor of a western state, you want to have a planning process and contracting and a systematic way to make sure that you have the resources when a contingency occurs. Hoping that the possibility of a high spot price once in a great while will be enough to convince people to invest seems to be enormously risky.

Comment: I would support bilateral contracting and a market that allows you to contract forward. This gives you the chance to go forward as long as you want, and to get as much capacity, and takes into consideration the type of resources you have. If you have a lot of hydro that is impacting the market, you may want a higher reserve margin than another type of system. I know of a state that contracts for renewables – great because it gets you off dependency on oil and gas -- but will not contract for baseload coal that might be cheaper in the long term.

Comment: There are two differences looking back to the 1970s: market design and restructuring, and growth. Then was growing at 6-7 percent yearly and now it is hardly growing at all. That has a major impact on the functioning of markets that have to deal with long-lived assets. I doubt that a market totally based on short-term pricing will make the right investment decisions. In competitive markets, there will always be firms that make wrong -- mostly excessive -- investment decisions. The question is are we willing to live with the boom-and-bust cycle, which I think would be the result of relying totally on the short-term markets, or will we acknowledge that if we have a boom, that regulators will interfere and if we have a bust for a long time, regulators will also interfere? We have to create some stronger long-term markets. One way is bilateral contracts.*Response:* Over the last year, the word "trading" ahs become almost a four-letter word. That is unfortunate because traders bring liquidity in the system, allowing different products and forward markets to function. We need to re-establish that sector.

Comment: For me, energy-only is shorthand for energy ancillary services, operating reserves and so forth, priced in the short-term market, and people contract bilaterally long-term to hedge against those in ways that are consistent with their own choices and preferences. I am not saying people should be relying upon the spot market and only energy. That is not the idea. But that is not what actually happens.

Session Three. The Costs and Benefits of Cost-Benefit Studies

Cost-benefit studies aid in making policy, economic and environmental decisions. Further, cost-benefit studies provide the means for supporters or opponents of policy initiatives. In electricity restructuring, they have been used to examine the merits of SMD, RTOs and LMP. It takes good questions to elicit good answers. Hence, the architectural design of a cost-benefit study is as important as its construction. Can we identify the key factors that make such studies worthwhile? What have we learned about their use in electricity restructuring? What questions should always be asked and answered, if possible? How should studies be structured, particularly if they will be used later for comparison in other regions?

Speaker One

In California, Market Design 2002 is a proposal to generally reform the ancillary service markets and congestion management practices at CAISO, and to move toward an LMP-based regime. Discussions over the past year and a half have refined and developed this proposal. Now we have a solid proposal that addresses all the identified deficiencies in the market.

In February 2003 the California legislature requested a peer-reviewed cost-benefit analysis of moving to LMP. After discussions with the state's policymakers and market participants we will focus on the real issues, questions and concerns that people have with respect to the assorted features of the market that we propose.

To date, the three views held are: the supplier community that favors LMP; LMP supporters who do not see the practical use of proceeding with any cost-benefit study; and those who are generally supportive of reform but not ready to commit publicly until the larger picture is clarified. The state's major LSEs are attempting to define and refine the rules for procurement before the PUC. Others believe an LMP-based system will erode existing rights, impose additional risks or expose cross-subsidies that are not entirely transparent under the current regime.

LMP has become the catchword for the collective angst and churn about whether to develop a viable and competitive marketplace. The predominance of hydro in the west affects California's other resources: the thermal resources that are emission-limited and the sundry other limited-use resources throughout the system. Legitimately, resource owners are concerned about how those resources will be managed and/or used once CAISO implements a centrally optimized market.

There is also concern about the many contracts the state has entered, during and subsequent to the crisis. Managing those contracts will be difficult in an LMP-based regime and will impose additional costs on California because of the contractual structure. Some are seller's choice contracts, which provide the suppliers discretion about where they deliver in the system.

We must apply a rigorous approach, and work hard to educate people. How you function within the complex market designs will take time to understand, and requires a transition for most players as they grow comfortable with the system. We focus on two things: reforming the core functions of how we use and allocate the transmission system and how we ensure reliable system operation. Important issues such as the resource adequacy framework must also be established in the state. We tell the policy makers that in essence, LMP is a means to use and allocate the transmission system transparently to align system operation with the pricing of the congestion management system or the pricing of the transmission system with the needs of the system operators. While it is important to further development of infrastructure from a price signal and an incentive standpoint, we do not represent that transmission and generation will appear magically. Policymakers also have many issues they need to address at the state level.

I believe that the DOE study is instructive because it highlights the need for both quantitative and qualitative approaches. It looked at quantifying the impact on increased trading on the wholesale and retail electricity prices and near-term changes in the use of the grid. The DOE study noted the infeasibility of conducting a comprehensive assessment on the impact on electricity prices, infrastructure development, security and reliability and the potential benefits of demand response. Policymakers usually want to know the effect upon prices and infrastructure development and they want to see hard numbers.

Perhaps this is an oversimplification, but the requested analysis of LMP in California is really a next-generation analysis. We captured the trading benefits of a consolidated control area operation and some of the efficiencies. Now, can we identify and quantify the benefits associated with central optimization?

There are five recent cost-benefit studies to look at: RTO West; SeTrans; New Zealand on LMP; NERTO; and DOE. It is also important to examine PJM; New York; MISO; New England; ERCOT, and the anecdotal evidence about their transitions, benefits, market transparency and price signals. We also should look at what I call the counterfactual: what happens if you do not redesign? What if MD02 is not in place?

The prospects of continuing under the California design are likely to grow worse. Many of you may know that the generation recently added in the west is undeliverable in the existing system because of inadequate infrastructure on the transmission side and the lack of an accurate pricing regime that efficiently allocates use. New generation in Mexico is also having difficulty getting onto the system.

Simulation studies will be subject to criticism about the assumptions used. Path 15 demonstrates a situation in which an economic transmission project was not needed for reliability, although there were tangible reliability benefits. We made assumptions about new generation, where it would come from and which of this new generation directly impacted the outcome of our economic analysis. We also made assumptions about existing transmission contracts, the extent to which they would be used and how they would impact the system. We are conducting an historical analysis using historical bids to simulate what might occur under the future design.

In summary, any quantitative study to support LMP in California will probably be inconclusive and will be criticized as unrealistic. Policymakers must understand what is likely to happen should we not proceed. Such studies really force you to apply a rigor about the questions you want to ask and about the real issues.

Speaker Two

Cost-benefit studies estimate the social benefits and costs of something, but is it wholesale competition, retail, establishing RTOs, or the implementation of SMD? We are halfway to competition, some RTOS are already established and at least some of those are close to SMD.

For the purposes of this presentation, I talk about short-run and long-run benefits. I categorize efficient dispatch and congestion management as short-run; and we know a little about how to quantify those. I also put non-discriminatory access in this category, but it must be addressed qualitatively. The long-run category is difficult to study. It involves virtually any kind of investments in transmission planning, transmission expansion, how LMP will support and encourage efficient investment decisions, generation efficiency, how to achieve better heat rates or locate in a better spot on the grid. I also include market power mitigation in this category.

As yet there is relatively little reduced savings in operating utility control centers, so for the most part, we are talking about the administrative costs to the RTOs.

The four major studies are the ICF study done for FERC; the RTO West study that looked at WSEC; the SARUC study in the southern US; and the recent DOE study. I categorized the short-run and long-run benefits of those studies. All four have a similar message. In the short run, the benefit is about 20 cents per MWh and the incremental costs of moving forward are about 24 cents. In the long run, the benefits are more difficult to estimate. They are 35 cents to as much as a dollar per MWh. For comparison, the total costs in forming the RTOs works out to about 44 cents per MWh. This means that there is no net benefit in the short run because RTO costs roughly equally the dispatch cost savings. Three studies attempted to estimate the long-term benefits, with mixed results, due to the uncertainty about what is in the base case.

Another message is that RTOs are expensive. From a survey of FERC Form One data for 2000, the generation and transmission dispatch center costs for 84 of the largest jurisdictional utilities in the US is about $400 million annually. The costs will be about $1.4 billion annually, if you project the current costs estimates forward to where RTOs cover the entire country. I have not studied whether there is room for cost controls in this situation.

Are these messages trustworthy? Almost all of these studies used a hypothetical reduction in the so-called hurdle rate that creates inefficiencies. Putting inefficiency in as part of the base case is a judgment call and an art form. In my view the benefits are considerably more speculative in the long run. They are difficult to identify, verify and estimate. It is difficult to know whether they are attributable to competition generally, or to the institution of RTOs. I think of RTOs as part of the foundation to competition, and many of the long-run benefits like better investment decision will come out because of the profit motive has been unleashed.

Nor have these studies considered the increased capital requirements due to greater financial risks. Is a certain amount of additional capital needed to smooth out or manage the boom-and-bust cycle? These questions have not been well assessed as yet.

The long-run benefits really depend upon your point of view. Will an RTO or better pricing generate better demand response? Are heat rate improvements to generators attributable to SMD or competition generally? "Drilling down" to discover what is responsible for different improvements becomes more difficult. Such analysis can be static and does not capture the long-run risks and rewards very well.

Yet some of the risk-taking is important. For example, is merchant development needed for the long-run benefits? How much is such risk muted in the absence of retail choice? Does FERC policy by itself point the way to full competition? We are learning that federal and state politics also play a role. Florida might have an RTO but with no merchant plants, what do you have? Another question being asked these days is whether we are talking about discrimination or state-sanctioned preference.

In conclusion, the studies show that short-run dispatch savings are more or less absorbed by the RTOS that were forming. The long-run benefits are really important, but hard to quantify, because they are distinctly more speculative and appear to me to depend upon more than just the institution of RTOs. State decisions and merchants make a difference. The good news is that short-run dispatch savings more or less pay the rent, so that while we sort out the issues about moving to competition, at least we cover the costs we are now incurring.

Speaker Three

We have learned that there are functionally efficient energy markets, such as PJM. But it is not a functionally efficient capacity market. From today's standpoint and how we could characterize how well our markets function, PJM is often the exception that proves the point. If you can have difficulty with capacity markets in a pool that is so tightly integrated, how do you solve capacity problems in pools that are more complex and difficult to integrate?

Capacity market reform has not reached a point where we can all agree on the appropriate model. There is limited, regionally specific political support for LMP. Many people view electricity as an exceptional activity. The phrase, "firm is firm" is magic to utilities' ears and it has been difficult because of capacity market issues, to argue that we have a market solution to firm pricing in all parts of the US. And the benefits of market versus the regulated model are still a matter of opinion. Investment is at a standstill. Industry now must struggle with the problem of moral hazard and how people see the extent to which they can rely on regulators for consistent regulation. New money, plants and economic transmission lines will have to be pulled into the market. Of course LMP is extremely useful for that. Without it, how can you tell where you need to put capacity or transmission lines?

We will live in a hybrid world where there is still a lot of regulation, but it allows for limited market opportunities. We will not have SMD, but WMP – time will tell what the shelf life of that phrase is. We will have ten or more RTOs. The country will remain divided in believing that LMP is costly or it is beneficial. Within the LMP world, there will be places where functional capacity markets are designed. There will be no master plan for capacity markets.

And we are in the era of perpetual studies, part of the political process. The outcomes are often predetermined. When people ask a consultant, “Do you believe that it would be useful to have LMP?” and the consultant says no, I think there is a great chance that the consultant will not get the study.

What are the essential ingredients of better studies? First, power market reform is more than a ten-year process. Long-run effects are important. Do not measure vast ideas with small yardsticks. But if you to long-term, the cost of establishing markets is front-loaded.

Political geography will matter and there will be regional winners and losers in the short term. Studies tend to focus on energy prices because that is easy, but the long-term reality is that there should be a comparative advantage. The action will be in load pockets. Generation portfolio diversity also matters, and investment assumptions will rule. We cannot ignore the future role of transmission, because we have developed plenty of generation in the past decade but now we need to optimize that. Perhaps merchant transmission will be better funded. Will AC transfer increase only incrementally? You must put that into your models but the answer is not self-evident.

If you create the right model and do the right things, you will get savings from the more efficient utilization of existing capacity across existing transmission lines under RTO rules. Put investment behavior into your effort. A smaller forward spot spread effect is one in which the price of energy in the future may not necessarily be higher or lower on a consistent basis than the spot energy price, whatever your commitments from month to month.

In an efficient commodity market, the forward price and ultimate spot price ratio over time is close to zero. In other words, the market is unbiased. If you look at the world oil market or most currency markets, over time you do not systematically profit from buying or selling forward. If you did, obviously others would, too, and then the market is inefficient.

Today, PJM is the only electricity market that has attained the level of efficiency: where a buyer cannot be certain whether it is better to buy spot or forwards. In all other markets and in places where the markets are regulated systems, you will always pay a higher forward spread. Cost-benefit studies do not factor in this pricing relationship. It is the price of asking private investors to absorb the risk that you make bad investments that are reflected in forward prices.

For every dollar of reduction in the forward premium in the combined MISO-SPP-PPJM market, there are consumer savings of about two billion dollars annually. Therefore, this common market will generate economic benefits that can be measured in billions of dollars per year if the efficiency of forward and spot pricing is added. The regulators and elected leaders are key, and we must be very shrewd about the true relationship among nature, people and power flows and we have not yet gotten that piece right. FERC’s vision of SMD died because the political leaders were unwilling to spend political capital to make it happen. I admire the NYMEX oil and gas markets that have worked beautifully over the years. Within their highly regulated structure, there is a frenzy of economic activity that has controlled and governed world oil prices and controls and governs US natural gas prices. Something like this will happen in electricity, but it is a hybrid model. Everyone will be in the same organization in this hybrid model. Well done, FERC. Meanwhile as we study and assess and worry, we should try not to succumb to trader's hubris. This is a complicated business and we still have not figured it out.

Speaker Four

At a basic level, you write down the total costs and benefits and take the difference. If the difference is positive, you think twice about the policy; if the difference is negative, you do not necessarily go forward with it. While very appealing, this simple accounting view can be misleading. Assuming that you actually have numbers that reflect the costs and benefits, several issues arise.

First, think about how to weight current costs versus future benefits. This is particularly relevant to global warming. Policies designed to deal with global warming clearly involve some current costs, but they are designed to mitigate some future catastrophe or the possibility of a future catastrophe. How do you weight current consumers' higher costs versus the benefits that will be gained for future generations? Nuclear power is an example of current benefits versus future costs.

Think about how to weight the benefits or costs to different stakeholders, such as consumer versus shareholder interests; or shareholders of utilities, merchant firms and shareholder employees. Some IOUs reduce staffing at generating plants when faced with restructuring. While this is presumably a win for shareholders and consumers, some employees lose jobs. How you weight and discount different stakeholders' interests varies as a function of your political constituency and discount rates vary as a function of your security of time in office if you are a politician.

However, I think the simple accounting approach can be misleading at a deeper level because no one really knows where the numbers come from. James Bushnell and I are studying the effect of divestiture on heat rates. We had to come up with what the heat rates would have been if IOUs had continued to own the plants. These examples demonstrate how the counterfactual can drive the results of the questions that you frame.

A counterfactual might be that the heat rate before and after divestiture would be the same. Using Southern California Edison's El Segundo plant as an example, we looked at the heat rates in 1997 and in 2000. The year 1997 was an El Nino year. There was a lot of hydro, so plants were operating less than in 2000. The data were such that the heat rates after divestiture included a lot of cold months, or if there were more summer months before divestiture than after, there might be a lower heat rate because of the way weather factors into power technology. Other counterfactuals are the changes in heat rates at other California plants, or plants within WECC that are similar to El Segundo. Another is called a difference in differences estimate. It uses the difference in plants that were not divested as the control or counterfactual.

We used the EPA continuous emissions monitoring system, or the CEMS data to get hourly unit-level heat rates. We saw some improvements for some of the El Segundo units over 25 MW. The divested plants improved their heat rates by about 2.6 percent. But when you factor in the improvements overall and compare that to changes at the non-divested plant, the improvements are smaller.

We also divided the sets of divestitures into states that had wholesale markets and states that did not. Our estimates suggest that the divested companies figured out how to operate to get two and a half percent more out of the plant for the same amount of fuel. This is about one dollar per MWh at current fuel prices and could add up to about four billion dollars of savings annually when projected to divesting every single plant in the US.

However, again it depends on how you frame your question and what policy experiment you run. Have the divested plants improved? If you project that into divesting every single plant out there, would you see the same improvements? This is a more difficult question: there might be an aspect of the plants chosen for divestment that makes them particularly ripe for improvement.

There are two other industries that have deregulated. Before restructuring and the breakup of AT&T, long-distance rates cross-subsidized local service. After restructuring, it turned out that having lower long-distance charges added up to more local service because many more low-income people got local access and signed up for phone service. In the airline industry, small towns were cross-subsidized implicitly by services on the major routes. But no one forecast how extensively the hub-and-spoke system would be used and how it would continue to provide small towns with service.

So expected costs did not materialize in both industries. I think this is part of our implicit qualitative cost-benefit analysis. As we sit down and write things out, we must realize that things will come out of our analysis that no one has anticipated. How do we handle this uncertainty? The question is about the correct standard of proof. If reasonable people can agree on it, is that enough to write down as a benefit or a cost? We can try to model it: there is a 50 percent chance you will be in this state of the world and a 50 percent chance you will be in another. In each case, what are the expected costs and benefits?

However, risk is not the same thing as uncertainty. Uncertainty is when someone hands you a coin and you only see one side. You do not know if there is a head on the other side, a head on both sides, or if the coin is weighted. You just cannot plug in the 50-50 numbers. Forcing people to put numbers on things does not really deal with uncertainty.

To conclude, if nothing else cost-benefit studies help us collect and summarize what we do know about the effects of policies. They might encourage analyses that will enlighten us. They might encourage is to collect new information that we would not have gotten otherwise. The costs are that the studies provide a false sense of security – the number you come up with means something to people. It is a billion dollars or ten billion dollars. And maybe there is neither a cost nor a benefit. Maybe it is just the actual cost of doing the studies because politicians can probably stack them in the way they frame both the question and the counterfactual.

Discussion

Comment: Before comparing RTO costs to the costs of the incumbent utilities, we need to understand that most utilities, including the big ones, combine the RTOs' control area and security functions with gathering data on the physical assets and operations, like breaker operations, transformer status, switch status and line flows. When you break the system apart, there are diseconomies of scale vertically because utilities still perform this function. There are some embedded costs that put stresses on the system as a result of the Energy Policy Act of 1992. I think you cannot lump all RTO costs as being balancing costs on a control area basis, nor can you take total G&T control center costs as reported on FERC Form One and conclude that is the cost of running a control area.

Response: I agree there are functions that we ask the RTOs to do that go beyond the balancing type.

Comment: FERC needs to renew its effort to reexamine the uniform system of account for RTOs and standardize RTO cost recovery.

Comment: I agree that there has been inefficiency as far as a reduction of staff at the utility level. Many functions are undertaken that were people failed to anticipate, especially in central data collection. It has entailed a tremendous amount of staff time and production.

Comment: After things stabilize and mature, I think there will be reductions in the operating costs of RTOs in the 20-30 percent range and that the incumbent utilities will pare down.

Question: Has there been any meta-study that systematically looked at the biases in cost-benefit studies?

Response: I am unaware of any back casting that says we projected this as a cost, but what the actual costs were. I think that kind of study is plagued by the same problems of a forward-looking study: it is difficult to reconstruct the counterfactual.

Comment: The counterfactual is difficult in the historical context because you would have to ask what it would have been like without the structural reform.

Comment: Cost-benefit studies ought to look more at the market potential. Are there rigorous tools to introduce X inefficiencies in the models so they are not the broad technical efficient, or technical market? For example, if there are a billion people in China, I suppose the market for sneakers is a billion pairs but the market potential is presumably quite a bit smaller.

Comment: We could add X inefficiency by looking at the structure of prices as real markets emerge. In a workable market, a forward price emerges. The issue of liquidity and forward price premiums is the first cousin of the investment issue and the X inefficiency issue. An investment question to ask is to what extent the formation of RTOs and LMP actually motivate people to invest. To the extent people do not invest, there are pockets of illiquidity in the markets. Those are inefficiencies where the forward price becomes very high compared to the spot price because people must build in a bigger and bigger premium.

Response: How would merchant plants be dispatched inside a control area if you did not have RTO? The models assume that the merchant plants are dispatched perfectly in the base case and then there is no improvement. In fact, there is probably more inefficiency in the base case than you are able to easily capture in the models. Does that amount to another ten percent on the short-run savings side? The longer-term benefits will be much more important.

Response: Engineers have production cost models that assume perfect competition and economists have models of how bidding behavior might be affected by incentives to bid other than one's costs. Ideally there will be refinements that marry in-depth production cost data with more economic models.

Comment: Retail ratemaking and the policies at the state level can really destroy any positive incentives you establish in the spot market. It is difficult to capture the longer-term benefits of SMD, LMP or MD 2002 without having a better sense of the larger framework.

Question: Economists do not have good models of bidding behavior for electricity. How do people recover their diverse capital costs when those are dependent on when you bought, your location and the capital cost recovery marketplace you are in?

Response: We can study the startup and development of new RTOs. There is a cost differential, too in starting a bad market design, and adding unnecessary things like separating a PX from the ISO. Area regulation costs go way up if you have a bad market design, because as a system operator, if you cannot do it with the energy you will with a different control product. If each time you expand the administrative costs to expand the footprint, you increase the numerator, but your denominator goes down. Overall there are savings, but PJM is finding that they are becoming stakeholder driven.

Response: There are certain products and services that stakeholders want from an RTO. Presumably, wanting them and being willing to pay for them means that per se, they pass a cost-benefit test. We have been unable to address that. We ought to be at least ten percent better off on the basis of technology transfer: if PJM knows how to do it, when it is transferred to TVA or SPP or West Connect, it ought to be a little cheaper the next time. But this does not answer your question about the services provided by the RTO that are themselves valuable because the stakeholders want them.

Response: You must distinguish between capturing the largest benefits of RTO formation versus the cost benefits of incremental improvements. I think as we move forward that knowledge grows and the way to do things becomes clearer.

Response: California's MD 02 has features that are sub-optimal, but are demanded by the market participants. To the extent that you compromise in any study that you undertake, you could lose some of the benefits of moving to a new market design.

Question: What long-term benefits can be obtained from a power pool?

Response: Every power pool study to date found a production cost savings of roughly one percentage point of production costs, plus or minus.

Comment: Very few cost-benefit studies come out in the opposite direction of the entity that does it. Go in with an idea, come out with proof and it is only orders of magnitude. I don't know anyone who buys too deeply into such studies.

Comment: I think PJM stacks up well. It has a capacity market problem, but that is not so big a problem as it is elsewhere.

Comment: Politicians are not the only ones that stack cost-benefit studies. For example, comparing McCullough's critique of Cambridge Energy Research Associates' study shows basic disagreement about whether there was a drought during California's energy crisis. Some generators that used to oppose LMP now they favor it, while some consumer interests now oppose it. It is almost as though the notion that there could be an objective analysis has been lost.

Response. There will never be absolute agreement and clarity. Look at the 50-year debate Americans have had about diet. Why should it be clear how we are supposed to govern our electric system?

Response: I do not disagree that such studies are political cover and we ought to look at who funds them. On the other hand, any good idea can be taken too far.

Comment: A lot of things are "politics in drag" but that does not mean that it is necessarily bad. In a certain sense it is unavoidable. Is it better to have the old system with the vertically integrated monopolies, or a new system in which we have a competitive market? For true believers in markets, it is mostly driven by investment and innovation and questions of dynamic efficiency. Given that you want to capture those dynamic benefits, how do you go about implementing the market? Ignore the perverse behavior that the rules create and let people do what they want and in a market where they are allowed to make their own choices. That was PJM in 1997. People made decisions that were completely inconsistent with what was needed for operation and reliability and the whole thing collapsed very fast. This failure mode is not captured by cost-benefit studies. The other response is not to allow that because of the operational problems that are created. This creates another problem because now people have the wrong incentives to invest. You do not get the long-run benefits of the wholesale competitive market because the pricing mechanism is absent. And that is not captured by cost-benefit studies.

Question: Do you anticipate establishing standards for the cost-benefit analyses referenced in FERC's SMD NOPR?

Response: When people come to FERC, we will work with them to explain the rules. It can be difficult for people who have not experienced SMD to sit down with paper and pencil and experience it.

Comment: I would like to see a clearly documented analysis about what has happened in New England, PJM and California, as opposed to a perspective or simulated study about what could happen. To a degree, I share your cynicism about performing these studies. But they have forced policymakers to really think about the answers they seek and the alternatives. It applies a discipline and a rigor that is beneficial. It almost forces people to understand things better and I believe there is a benefit to going through the exercise. I do think the results have questionable value.

Comment: This is more about process than produce and the process is actually quite good. In some sense, in the very end, the product is irrelevant. You have to do it, and that is the discipline for doing it, but it is more about the insight that people gain along the way.