Harvard Electricity Policy Group
Thirty-Ninth Plenary Session

Cambridge, Massachusetts
May 19-20, 2005

RAPPORTEUR'S SUMMARY*

Session One. Electricity Restructuring Policy: Looking Back and Planning Ahead.

Hindsight does not always assure perfect vision. The lessons learned in electricity restructuring should be important in shaping the prospective policy agenda. But an accurate prescription depends on the quality of the diagnosis, both about the history of the arguments and the context of the analysis. Looking back to the national debate and the microcosm within the Harvard Electricity Policy Group, we can assess the challenges that remain. What drove us to electricity restructuring and greater reliance on markets? If the initial driver was expectations about electricity prices that have proven to be wildly unrealistic, what should be the goal now? What U.S. institutional characteristics – a fragmented industry, heterogeneous regulation and ownership, Congress and the Courts – were significant in shaping the path of evolution in the United States? What roles will or should they play in the future? What were the differences and similarities that applied to retail and wholesale markets? How did participants approach the policy problem? What were the major mistakes and what did we get largely right? To what extent are the lessons learned embedded in current policy or at risk of being lost? What mistakes should we avoid repeating? How should we move forward? Are there particular regions that will prove pivotal in the next wave of restructuring? Is a revolutionary approach conceivable? Can an evolutionary approach work?

Speaker One

Why did we start down this path? First, electricity prices were perceived to be extremely high in regions that opened markets. If we deregulated generation, we'd get cheaper electricity. We'd achieve a new alignment so that people, who were going to make decisions were going to bear the consequences. Second, we thought it would lead to all kinds of nifty new value-added services. Finally, some wanted to punish incumbents, incompetent utility managers, and misguided regulators as much as possible.

What did we get largely right? Two things: First, stranded cost. It was initially thought that we would never be able to get past it but we have. Whether it was fair depends on whether or not your ox was gored. But the issue almost never even comes up anymore. Second, the basic principles of workable competitive markets were realized. The rules need to reflect the underlying physics of the grid, and if they don't, it sets up opportunities for people to do things that are harmful to the system. These are the core features for workable wholesale markets. They are necessary, but not sufficient conditions for well-functioning markets.

What did we get largely wrong? The potential to get efficiency gains in generation in the short term was missed, especially in the economics of commodity retailing. It's safe to say that almost nobody really understood this when we opened retail markets to competition. In addition, the myth about how quickly we would achieve savings was an overstatement. There was the perception that if we opened up markets, electricity costs would go down by 50 percent. Competition has brought real efficiency gains but they're relatively modest, relative to what was expected.

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

How did they get there? Well, some said, "Do you think we're going to have two dollar gas forever?" However, there was a protracted recession in California and upstate New York that created excess capacity. The question fell on deaf ears. The expectation for savings and gains was almost impossible to dispel.

The real difference between a competitive market and a regulated monopoly is not so much the technology choices -- although competition does spur innovation over time -- but rather the forecast risk inherent in the business. It's a capital-intensive, and more volatile than other commodities. Neither system is better at forecasting what's going to happen. The merchant generators of the 1990s weren't any better at forecasting fuel prices and capacity than monopolies were in the 1980s.

However, the market system shifts who bears the consequences of the decision that is made. That is the real difference and benefit of a competitive market, It is an explicit choice about who's going to decide what gets done, what plants get built, and so forth.

Looking ahead, we have to focus on workable wholesale markets. Not only is it the law of the land, but there isn't any serious support to roll back reforms at the wholesale level. We should go slowly with retail markets for awhile, and do some things differently.

The mass market is my focus for retail market competition: residential and small commercial customers. One problem is that you have small loads, and thin margins. This is not just because there is the valid need for regulated service, but also because of high transaction costs and no value-added services to offset them. The retailer going after these small loads can't create enough value for a customer to sort out who they should buy from and make the effort to write two checks instead of one for that service. That's a hard reality of economics.

We also need to consider supply risk. If markets are about aligning decision-making and cost incurrence, are small retail customers really able to deal with this? Our best forecasts suggest that in a few years, costs will be somewhere between $30 and $75–$80 a megawatt hour, with a 20 percent chance of being outside that boundary. If this is really where the value is, the decision-making about that really fits with residential customers.

We need some retail load in the market, but we don't need all of it to get working wholesale competition. Given these economics, is it a good idea to continue to force small retail customers? It's expensive to force them to switch and this pushes costs into the system. It makes the regulated default service work at cross-purposes to cost-reduction. If you set it too low, no new supplier can compete. If you set it high, most customers stay with default service anyway because it has to be really high to make it worth the extra work and they pay way more than they should have to.

An alternative is to limit retail competition solely to large customers. Or here's a completely different thought for the United States -- instead of trying to get incumbents out of the business, and keeping score by how many people didn't buy from the incumbent, encourage incumbent utilities to stay in commodity retailing and go after each other's customers. Why? Because these are the businesses that have scale economies in retailing, call centers, billing systems. They are used to dealing with lots of customers.

While we have to deal with this current structure, it doesn't mean that a revolutionary approach can't happen. However, there isn't a central authority where a change in political parties can mean a complete change in direction. There's no critical mass of support for it, anyway. We're not going to get federal legislation that's going to completely redefine ownership and regulation.

This inevitably means that progress is going to have to be incremental and evolutionary. It will be grounded in the markets that we have right now. Progress will be measured by the future position of these regions relative to where they are today.

Now, what should this industry focus on? Forums like this bring unique combinations of people together fills an important need. They are useful for maintaining focus on the fundamental underlying issues. They ensure that key stakeholders on all sides are heard. The next generation should focus on these nitty-gritty wholesale issues.

We do need periodic history lessons because there's a whole new generation of regulators and utility people who don't have the right background knowledge. They are starting to propose things that repeat mistakes we made in the 1990s, in the first phase of restructuring, but also mistakes from the 1970s and the 1980s that led to restructuring in the first place. We're not doing our jobs if we don't periodically remind people that there's a reason we're not doing certain things.

Speaker Two

My perspective comes from my role as a foot soldier in restructuring -- drafting comments; participating in stakeholder conferences; occasionally filing complaints; and trying to help my organization address the tumultuous events of the past decade. I remain optimistic because neither overblown rhetoric, nor misplaced motivations have prevented the emergence of powerful ideas that are rapidly changing this industry.

It's helpful to start by asking what problem we should be trying to solve. The most compelling problem lies in the need to consolidate transmission facilities that evolved independently over a century of public and private continental development. These were constructed initially to serve the needs of a specific community, company, or government-owned project. However, the usefulness of local control and vertical integration as the primary organizing principles diminished over time. By the 1990s, U.S. transmission facilities in the United States had actually matured into crude *de facto* regional networks despite balkanization and regulatory issues. The emergence of independently-owned generation demonstrated that a vertically integrated ownership structure was not a natural monopoly. The changing circumstances demanded more powerful concepts be adopted to extract the intrinsic value of the grid, such as competition, horizontal integration, efficiency, and standardization.

These considerations are far too dry and sensible to be the reason why federal and state regulators have spent so much time and political capital over the past ten years trying to restructure this industry. What really drove the history is a story about two independent regulatory initiatives, one east coast and federal, and the other west coast and state, that converged unexpectedly and produced a revolutionary market design model that no one expected.

In the mid-1980s, FERC was flush with success in requiring gas pipelines to unbundle transportation service from commodity sales. They sought a similar result for electricity and opened an inquiry into electric transmission pricing. Passage of the 1992 Energy Policy Act served to reinvigorate the FERC's efforts to promote third-party transmission service. This resulted in Order 888 in 1996. However, it lacked effective implementation measures, and incorporated the contract path pricing fiction. It did establish non-discrimination legal standards, but failed to effectively define third-party transmission service capable of facilitating the more efficient dispatch of generation, regardless of ownership.

Meanwhile, in 1994, the California Public Utilities Commission proposed retail competition. They did not understand that retail competition could not be introduced safely without creating an upstream wholesale market platform under FERC jurisdiction first. Thus, the California Blue Book proceeding, while nominally directed toward state-regulated retail issues surrounding customer choice, almost immediately devolved into a fractious debate about cooperative federalism and the unfinished FERC work related to the provision and pricing of efficient third-party transmission service. Ironically, the spirited California conversation allowed for the emergence of many ideas that would emerge 7 years later in the FERC's SMD [standard market design] rule-making. While some of these ideas were adopted in the California Commission's second and last policy decision, there were few who recognized their inherent worth, and the new California tariff discarded them.

Fortunately, the PJM and New York power pools had been paying attention. These institutions successfully deployed a new market design to comply with Order 888 while California was condemned to wander through the 2000–2001 energy crisis with a market design that didn't work in theory nor practice. A chastened California ISO has embraced the new market design for implementation by 2007, 13 years after it was first introduced there.

There are three conclusions. First, despite the failures just described, the tree of restructuring has taken root, and now overshadows much of the electric industry. Second, while much of the fruit harvested from the restructuring tree over the past two years has been inedible or downright poisonous, we have nevertheless survived to learn that parts of the tree produce nutritious fruit. This is transforming the industry for the better. Consider two "fruit choices." One, independent system operators have consolidated control areas under a standard tariff to enhance system reliability. Two, short run markets, based on locational marginal pricing and financial property rights, provide efficient re-dispatch services and support non-discriminatory transmission service. Third, the U.S. political and legal systems are biased in favor of markets over monopoly. Since many industry "thought-leaders" have eaten the nutritious fruit, there can be no chopping down of the restructuring tree. Instead, transmission owners must find repose under the shade of that tree by adopting practices that will enable them to stop wheeling and start dealing.

Speaker Three

The previous remarks provide a helpful framework to discuss mass market competition. Despite concerted efforts in some jurisdictions in the United States and around the world, there have been no effective competitive markets for mass market customers. There are one or two notable exceptions.

Several states have made aggressive restructuring efforts at the retail level. It's been extremely successful with industrial customers. In cases such as Illinois, New York or Maine, you've got 60–80 percent of the load now utilizing competitive supply. The most important advocates for deregulation have received benefits in choice, contract, and the ability to separate their commodity purchase from their incumbent distribution company. This model has worked for industrials, and to a lesser degree but still significantly for the commercial customers. It has not worked for the residential customers. Many states, despite extensive effort, are still below 1 percent of customers switching, with a couple of exceptions showing greater numbers. Texas is the largest by far. This provides a glimpse of what lessons may be learned about how to serve these customers.

The absence of market competition for these customers exposes them to the full force of wholesale market price fluctuations. Default service involves a pass-through of the market price, usually under short-term conditions. These customers cannot obtain any significant hedging capability that could be provided to them by a competitive retail supplier.

Regulators often pressure retail distribution companies to develop supply portfolios. This is a backwards strategy which puts the distribution company back in the role of assuming supply-related risk. Restructuring was meant to remove distribution companies from the business of managing supply portfolios, and put it where it belongs, which is on competitive commodity managers.

The lack of price discovery at retail causes prices to be higher than necessary. When you have one or two transactions purchasing supply for several million customers, you don't get the vigorous price discovery that you would occur from thousands of transactions with smaller groups of customers. This is a plain vanilla product that they're getting. There is little or no innovation around products and services and this maintains inefficiencies.. There isn't an opportunity for green products to develop or other kinds of dual marketing of commodities.

A lack of stable customer relationships with suppliers also inhibits long-term supply contracts and the construction of new generation. This is where the evolution and maturing of the retail market connects to the development of the wholesale market. In a deregulated marketplace, it is one way to provide incentives for market participants to enter into long-term supply contracts which would motivate the construction of new generation. One solution is for the government to require distribution companies to buy long. But that is a backwards strategy. In a healthy, mature retail market where many customers are committed to suppliers long-term, the incentives to invest in new generation are already there. That's the basis for a portfolio that includes steel in the ground, a mix of long and short-term supply contracts, and some spot market activity. Big industrial customers have a 1 or 2-year horizon, and then they want to play the market again. The absence of these small customers become important when you get into millions of them. This is the weakness in the overall strength of a restructured market.

The Massachusetts experience is illustrative. Their deregulation commenced with a statute in 1997, where all customers, including residentials, were free to choose. Retail suppliers had to guarantee open access to the wires if customers wanted a competitive supplier. All legacy customers were guaranteed a 15% rate production through "standard offer" service. This meant that distribution companies sold or spun off three billion dollars in generating assets to facilitate competition. They could recover above-market stranded costs, but had to credit those asset sales back to the stranded cost-recovery accounts of these customers. There was a correcting mechanism there because these assets had real value; more than anyone anticipated at the time. Customers benefited from reduced stranded costs. The structuring of the standard offer seemed quite elegant: the generation price would start low, at the two/two and a half cent market price, and it would rise each year for seven years.

At the same time, stranded costs for customers would decrease. Overall, customers would see roughly the same price delivered over the seven-year period. But within that total bill was a steadily increasing generation price which would go above market gradually. It would provide encouragement to customers to move to competitive suppliers. The progression of generation prices could provide a good benchmark for customers, so they could determine whether any value existed in the competitive marketplace. As it turned out, we got it wrong. No one anticipated that prices would be driven up, especially by concurrent natural gas price. For seven years, market prices stayed *above* standard offer prices. Thus, only the largest customers could be offered discounts and be served profitably. Most medium and small commercial customers stayed on the supply for seven years. Only about 50,000 or so residential customers were able to get access to competitive supply through municipal aggregation. Few residential customers have moved to competitive supply. It increases ever so slightly above zero in 2003 and 2004 from municipal aggregation. All other customers were on standard offer or default service at the end of 2004.

In March 2005, standard offer came to an end; everyone was moved to default service. We now have about two million small customers, residential and small commercial, on what's now called basic service. It's a fairly unstable pricing regime, probably by design. Every six months, 50 percent of the load is purchased for a one-year term. Customers see supply changes every six months and distribution companies pass through this service to customers. They cannot mark up or make any profit on this so they're not happy providing it. The only people who are happy are the suppliers who are winning these bids. Even they find it difficult because they have to reserve a lot of supply in order to be able to bid. If they don't win the bid, they must sell it in the short-term market, and six months or a year later, be ready to bid it again.

It's a very short-term type of generation purchasing regime. Currently, the Massachusetts PUC is reexamining the whole process. It has precipitated a vigorous debate over long versus short-term supply incentives. Those who don't believe that competition is viable for these customers say that the government's got to get back in this. We should require the distribution companies to develop a portfolio of contracts and supplies. Maybe -- no one says it – they should get into generation ownership again. Forget the lessons about stranded costs and allocation of risk that motivated all this in the first place.

Has anyone else faced this problem and solved it? Lots have faced it. We looked at 11 others besides Massachusetts; including Australia, the United Kingdom, Alberta, Canada, and eight other states around the country which had attempted to facilitate retail competition. Their experiences have, in most cases, been much like that of Massachusetts. We were able to segregate the type of method using full retail separation as a focal point. This model lets incumbents keep customers, but separate their business into regulated distribution and transmission business. They take those customers forward, and now compete against each other.

Direct customer assignment has been used in Georgia for the natural gas markets there even though it wasn't an electricity model. Here the incumbent puts up all their customers and auctions them to competitive suppliers -- the "big bang" approach. It was difficult in implementation, but Georgia now has the most effective mass-market energy commodity business in the world.

The competitive generation supply model used in Massachusetts and other states tries to provide a price signal for customers to move. We looked at six different states that used that model. We also examined Oregon, where distribution companies provided a portfolio for customers to choose from. These results were interesting. We also examined the natural gas market in Georgia and its direct customer assignment model. Finally, the United Kingdom showed remarkable results -- almost 40 percent of the mass market customers had chosen competitive suppliers, and more than that had active or competitive offers. There was also some switching in Ohio, the most successful state using competitive generation supply.

In all these markets, marketers face a set of barriers to competition. First, the cost to acquire a customer is high compared to the expected profits. There are expensive back office requirements. Most marketers believe they need a minimum customer base between a half million to a million. Otherwise, the infrastructure requirements are too great.

Second, the projected savings for any single customer are modest. They are not likely to move, at least initially. Third, the pricing of default service, can severely impede entry. Any opportunity to go back to default when market prices get high provides a free call option for customers. This wreaks havoc with any competitive supplier's supply planning. Fourth, the incumbent distribution company stays in the business, even if it's just supplying default service. It can provide the impression of a significant competitor; whereas retailers can't get name recognition or branding, in part because the incumbent still dominants the landscape.

However, certain features do encourage competition for these customers. One is the size of the potential market -- millions of customers. In the United Kingdom, 26 million customers provides an attractive opportunity if you can penetrate that market. Sensible and consistent market rules also have a positive effect on retailer entry, particularly around default service pricing. Most salient was that markets with the most competition -- the United Kingdom, Texas, and Alberta, Canada -- used some form of aggregation to transfer customers to supplier. The United Kingdom has become particularly competitive for these customers, while Texas, Alberta and others are on a good path to competition.

The evidence, while skimpy, is not entirely discouraging for these customers. It suggests that several strategies make a positive difference. One is to maintain a single, statewide model of choice. This preserves an attractive market size for retailers. For example, in Massachusetts, you wouldn't want to have one distribution company using one model to move forward while another uses a different model. With two million customers, Massachusetts is small by industry standards; balkanizing that market further restricts retail competition.

Market pricing for default service reflected through frequent competitive bidding is needed. Default service supply must stay current with the market and reflect the full cost of retail services, including billing and customer service costs. Direct assignment, customer aggregation, or retail separation models should be used to move customers to competitive suppliers. It cannot happen one by one by one. This is a mass market, not a single customer market.

Fortunately, the United Kingdom shows what's possible. More than 40 percent of the mass-market customers have switched to suppliers. Eighty percent of the customers can identify two or more suppliers by name. They're thinking and focusing on choice. Price discounts are common for switching and there are a lot of non-price features. These include loyalty points, bundled offers, green supplies, and bill insurance products. The suggestion that this is a plain vanilla commodity is disproved vividly by the UK experience, and also somewhat in Texas.

90 percent of the United Kingdom mass market electricity customers rated their experience with competition favorably. Customers are not necessarily unhappy with choice. Some argue that customers don't want to be bothered. This is not the case. Customers prefer to have a choice when they see the opportunity to claim value.

Last year, two Massachusetts state legislators proposed an aggregation scheme where customers would have been grouped randomly, and suppliers could bid to serve them for three years at a fixed price. They would have used a descending clock auction to be sure that all customers were paying the same for that three-year period. After three years, the suppliers would have kept those customers, subject to approval of the Public Utility Commission, for the price they were proposing to charge for the next three years. After the second three-year period, the customers would remain with the company. At any time, customers could opt out and go to last-resort service. None were obligated to stay with the suppliers. A few months after this proposal, one of the major distribution companies in the state endorsed it. It's still a work in progress but there's some good thinking going on.

In closing, competition can provide mass market customers with more diverse retail products, stable prices, and effective price discovery. We need more evidence to confirm that. Competitive suppliers do face significant barriers to serving these customers. They are high cost customers to serve, and the profit margins are small on an individual basis.

The challenges can be met through customer aggregation, but political leaders fear the risks of supplier failure or market power, and are reluctant to initiate these changes. The pervasive climate of problems since California continues to cause most political state-level leaders to be fearful of moving forward. The successful introduction of competition to the mass market is going to require convincing evidence and benefits. There is work yet to be done on this issue.

Speaker Four

I used to interact with system planners at a large southern utility. System planning is focused on choosing the least cost mix of resources, usually a mix of base and peaking plant. There were more choices years ago. If you project that mix onto marginal cost, it is similar to the way market prices would work if you ran the business as an auction and people compete to supply power using resources of different costs. An optimal system would provide marginal cost with high operating costs of a peaker for a few hours a year, and low operating costs for the rest of the year. The cost of a peaking plant is generally no more than $100 a megawatt hour on a bad day. We did end up with price drops most of the time, but also some extremely high price spikes. These go to a thousand dollars a megawatt hour, or above.

Should this have been expected? In system planning, we knew that you could not ever invest enough money to completely remove the chance of an outage. Back then, customer surveys helped us determine that they would be prepared to pay to avoid two hours of outage on a very hot summer day in the southeast. This results in zero capital cost, and high operating cost; a very steep curve. If you project that onto load duration, it's optimal to have around four hours of outage a year; otherwise you're spending too much money on reliability. Customers would rather have the blackout than have the rates that would result if you spend that extra capital cost.

Projections show very few hours -- about four a year -- at $8,000 a megawatt hour or more, and the rest of the curve as expected. This should have been expected; as well as the probability of outage. This aspect of the system has simply become explicit.

Interestingly, as a system starts to trade, volatility goes down. Price, instead of being an output of the system, becomes the mechanism whereby the system feeds back on itself and sends a signal to react to. This resulted, and should have been expected, in a few hours every few years of extremely high prices. It is the optimal outcome.

If the sole objective of deregulation was reduced prices, we were missing the point. One should also expect a more efficient allocation of capital; a lower overall cost on a risk-adjusted basis. This should provide faster dynamic response, less supply, demand, and balance. It should also offer customized products, giving customers what they want. These outcomes are not the same thing as reduced prices.

In all of this, commodities groups are providing price insurance. There's also an intermediation role in commodity markets. Contrary to everybody's expectations, when Enron went away, the market did not go away. In 2000, the top five players held 39 percent of the market share. In 2004, they only hold about a quarter of market share, and volume has gone up. This trend should continue.

We should also consider specialization. The market should allow people to contract out what they don't want to manage themselves. This requires a good regulatory and legal environment; otherwise, you're forced to deal with everything in-house. I want to stress this, a market that demonstrates vertical integration has failed. In general, if you can outsource risk, you're will be focused on a narrow range of risks in that market; a specialist. Commodities groups are specialists in price risk.

Discussion

QUESTION: You said these are long-term contracts. Is three to four years long-term, in your definition?

ANSWER: At three to four years, the bang for your buck is ideal at about that level under current conditions. You gain the optimum trade-off between the cost of financing and the hedge cost.

QUESTION: Do commodities groups finance plants in these deals?

ANSWER: No, they provide the off-take contract, and because they do that, investors are prepared to lend money.

QUESTION: What is the term on the debt?

ANSWER: It depends, but it's more than three. So long as you cover the first period, people will lend because you've diffused part of the debt by then.

QUESTION: Are these all gas projects?

ANSWER: No. for instance, Coleto Creek was not.

QUESTION: You've presented a cap or peak at which customers seem to be willing to pay. What conclusions did you draw from that, and do they influence the reasons for deregulating?

ANSWER: We should have expected short and extreme price spikes. Customer demand is inelastic, but it's not infinite. At some level of high price, a customer would rather not consume. It's an enduring mystery as to why utilities haven't been more aggressive in pursuing that. It's like going to your customers and giving them the opportunity to rip you off. They get electricity at seven cents a kilowatt. Give them 20 cents a kilowatt hour for every kilowatt hour used that's less than what was used at the same time last year. It's not efficient, but there would be a huge response. Most important is to consider risk-adjusted cost when one considers costs and benefits to society from deregulating.

MODERATOR: A couple of points this morning help connect the dots. Wholesale markets can and do work; they could work better. There's a lot of fine tuning to do. We'll need to do this incrementally, painful as it is. We should see growing evidence from some developed markets in the U.S. which should inform the rest of us. To make retail choice work, we need vibrant wholesale markets. We need to get the rules right and consistent over multi-state areas in order to appeal to the smaller customer beyond their transaction costs. Finally, there is a role for financial players in assuming risk and intermediating. Without an active role by them, we can see declines in liquidity.

QUESTION: One incremental change issue concerns the question of financial transmission rights and a move back toward longer term physical transmission rights, or a way to get longer-term financial transmission rights. Is a move towards physical rights an incremental change in the wrong way?

ANSWER: It's exactly the wrong way. The important thing we have learned is how to price transmission service. You cannot do physical property rights in an electric transmission grid; the best way is financial transmission rights. However, a certain mix of the financial transmission rights should be for maybe ten years. This would support new generation projects, long-term contracts, and the ability to hedge congestion for a longer term period.

QUESTION: Regarding consistency issues for wholesale and retail design, you suggested we put retail design in front of the wholesale process, or get a bad retail design that is accommodated through bad measures in the wholesale markets. Did I paraphrase you correctly? Is that an aggressive but necessary approach to the retail design problem?

Second, in nodal design markets, should we get customers off the retail system and make them nodal wholesale customers? Are both these suggestions the correct extension of your comments?

ANSWER: Large customers need to be in the market. In an ideal world, put them on wholesale. Unfortunately, billing problems can interfere with this, even with wholesale players. With extensive billing problems, it would be a problem to dump 10,000 more customers onto that billing system.

We spent so much time and energy worrying about the switching rules for retail markets, that we wasted enormous amounts of effort and resources very prematurely. These would have been better spent doing wholesale first, and then dealing with the retail, which would be a more natural fit.

QUESTION: That's exactly the point. The weight of stakeholder and ISO talent and effort to accommodate retail is disproportionate to the benefit. It also weighs against getting the right design at the wholesale level, and *then* figuring out the most accommodating retail design.

COMMENT: Another issue is demonstrated in Massachusetts' Standard Offer Service that existed from March, 1998 through February of this year. Massachusetts began restructuring in 1998 by giving legacy customers a 15 percent discount off their 1997 rates. This was very problematic. It was a constant source of regulatory and political headaches, and created significant market distortions over those seven years. One should avoid distorting the markets, and the regulatory process, with initial discounts like this.

QUESTION: We don't seem to see $8,000 per megawatt hour prices in the current ISO standard market design. Should the design allow for them? Second, would there be more incentive for retail competition and innovation in the mass retail supply market if there were high prices for customers to avoid? This can be done over the Internet with mass suppliers, or with commercial and industrial customers.

ANSWER: Those ISOs generally have explicit price caps. Not surprisingly, they're also worried about where new investment will emerge. If you hold prices down, a deficit of supply occurs; if they are too high, there's a deficit of consumption. These efforts lead to incredible distortion in the markets. We should allow 8,000–10,000 prices. If you want to cap at 10 or 15, that's OK, but one thousand is too low.

ANSWER: California is now capped at 250, not even a thousand. Politicians believe we can't raise spot prices because consumers might be hurt. They argue we can't have high prices that are reminiscent of California's past problems. At some point this will turn around. Consumer representatives will finally recognize that high or volatile spot prices are pro-consumer and lead to better long-term results for consumers. The alternative is to build a capacity market to supplement the missing money in the market.

Instead, we should protect consumers from volatility through hedging. If load-serving entities were hedging forward so that spot prices do not directly affect consumers, then people would say that volatile prices are a good thing. It helps with dispatch, to make sure we've got the right machines running at the right time. It helps folks with energy-limited machines to run only when they get the most value, and it completes the whole market and the loop of new capital investment. Until this is perceived by consumer protectors, we're condemned to building second and third-generation capacity markets instead of a well-designed energy market with hedging.

Instead, we had intervention and we are moving to ICAP. Certainly, we've got to ensure capacity, which dampens the volatility. However, this makes the customers happy to stay in the spot market, not paying for a hedge. This is a huge problem. We don't have a way out of this predicament.

COMMENT: Let's remember that energy efficiency can often be obtained for less than the cost of new generation. The biggest mistake in restructuring is that the role of utilities and resource procurement has been ignored. Having utilities as resource portfolio managers is a model that's reviving in the west. Utilities should be involved in long-term investments and this hasn't happened. No matter where you are on the spectrum of retail or wholesale competition, utilities as resource portfolio managers can work. You just need to get the incentives right to create incentives for energy efficiency.

ANSWER: In the 1980s, we justified utility intervention, promoting energy efficiency on the grounds of market failure. We argued that consumers couldn't see that oil would be $100 a barrel fifteen years out until we had to intervene and make them face the prices. Fast-forward to ten years later, and you see that this central planning model of $100-per-barrel oil was wrong. Gas was two dollars, not a gazillion dollars. Markets were right. We would never have gotten that result if we had let the market work. That is the central dilemma when you talk about promoting energy efficiency. Any provider of a service does well to help their customers use it efficiently, and for their best interests. But that's different than the programs of the 1980s, which required massive intervention.

ANSWER: Those who want to see demand side management on the load side clear the markets will need to be in favor of accurate wholesale prices, which are inherently volatile. This requires getting past this political third rail issue that prices always have to be low. Instead, use hedging and forward contracts to manage risk, especially for residential customers, and let the wholesale spot price be very accurate. This will promote a robust demand side clearing of the market.

COMMENT: Prices should tell the truth, but market barriers to the exist, especially with environmental problems. Intervention is needed to correct those barriers.

QUESTION: We've heard that the lack of stable customer relationships with suppliers inhibits development of long-term supply contracts and construction of new generation. That implies that commercial and industrials will switch more frequently than the retail customers, and that the additional uncertainty over future cash flow inhibits investment in new generation. While it may seem intuitively correct, is there any data to support that? Further, you seem to be arguing that competition at the retail level is perhaps not a good thing. How do you answer this concern?

ANSWER: I don't have empirical data to support those assertions. There might be implicit support for it in other circumstances. Consider how much residential customers have stayed with their incumbent companies, even in fully restructured markets. These customers are likely to be sticky. There's evidence of that all over where transactions are not short-term or one-time, but ongoing.

Alternately, large industrial customers are aggressive shoppers; they can analyze, research, and compare with other offers. They can take a lot of load away from one supplier and give it to another for minimal difference in benefit.

QUESTION: If retail customers are sticky, why go through the costs of implementing retail competition?

ANSWER: Large-scale wholesale purchase for these customers should give a competitive price. This requires someone to decide that all two million customers want exactly the same product, at the same time, in the same way, and on the same terms. Certainly, you can assert that having decided what they want, you're giving it to them on the best terms possible. However, two million customers will have strong differences in preference. These options are unavailable because it's impossible for anyone else to get any traction.

ANSWER: I have looked at the costs in some detail. There is compelling evidence that benefits do not outweigh costs for the residential segment. Consider sales and marketing costs, incentives to switch, and duplication of billing systems and call centers. These would increase costs to the average residential customer 20 percent.

Where is the additional value in residential? Fifty to sixty percent of a typical residential bill is transmission and distribution. Potential savings are only available there. Value-added services really didn't materialize. The only successful one was aggregation of services; and this can be done with a credit card (if a Commission will let you pass that cost through because it adds three percent to the bill). This may work later on but first solve the wholesale; focus on the big guys; get a stable platform and the major problems worked out. Don't spend all this time and effort trying to push the little guys into the market because you have to write all these rules for problems that you may never have because they never switch anyway.

QUESTION: In attempting to restructure markets, you do have to look at the biggest problems and the fundamental structures. You can't have a well-functioning retail market without a well-functioning market. However, the argument that the benefits do not outweigh the costs comes from assuming that customers all have the same willingness to pay, and they don't. If one presumes they all want the same product at the same time, at the same price, in the same way, you're essentially creating a fictitious customer and pretending everyone is like them. This isn't the case. We know they're different. Certainly, people have gotten used to the same product, at the same time, in the same way for decades. Can you change that overnight? No. You've got to work your way to that. A market will differentiate customers by determining what they want, and their willingness to pay.

QUESTION: We do have empirical evidence concerning some key issues surrounding commercial and industrial customers. First, a market-based rate provides a competitive and dynamic retail market, or allows for that opportunity to exist. This results in customers asking for demand response programs from the retail supplier, not the utility. They ask for hedged products and fixed products. Second, the largest customers (three, five, twenty megawatts) don't have a lot of loyalty on contract length. Underneath that, there is a lot of stickiness, consistent across most suppliers. The retention rate is 70–80 percent. The contract might be a year or two but the relationship is much longer. Third, they do want varying products. Recently, the largest customers have driven this. But now, customers from 1-5 megawatts are asking for different products and are interested in moving to retail suppliers. This leads to my two questions.

There's a big group of consumers in the middle class, as I would call them -- big box retailers, etc. They have more interest in competitive markets, but no one talks about them much. What do we do about them? Second, why does the mass market matter? Well, they matter politically. If we don't solve residential or small commercial problems, does that blow up the rest of it?

ANSWER: Those customers are frustrated with the middling paradigm; competition for big customers but not for small ones. For small customers, we're still going to have some variation on the old system. However, it's weak because we've removed distribution companies from generation. They don't own any ground any more. We also discourage long-term contracts because that raises the supply risk, stranded costs, etc. They're not free to be effective servants for small and middle class customers. These customers receive a static and unresponsive sort of product. They respond by demanding that government begin re-regulating. Failing to deliver competition to these customers over time will erode political support for restructuring and deregulation, at least at the retail level. This could result in distribution companies who take care of their competitive customers half the time, and the other half they're supposed to be the single monopoly supplier for non-competitive customers. It's a tension that's not resolvable.

COMMENT: First, why do we have problems in some areas and not others? We take for granted things like separations between distribution businesses, wires businesses, and retail. The most crucial factor is the extent to which the regulators describe prices. If they prescribe tight price controls or default services, or the way in which competition takes place, that kills the market. If we consider Texas, there's a relatively high cap; in the United Kingdom, they scrapped it; and there have never been any price caps in Scandinavia and the market flourishes.

Second, recent figures show that 48 percent of residentials have switched to another supplier in the United Kingdom (that is a net figure). In Texas, the gross figures of people who have ever switched are 10–20 percentage points higher as of December 2003. There was extensive switching last summer when there were some unexpected price increases; I'd be surprised if the net figure isn't now almost 60 percent.

Third, is all this worthwhile? Economists and regulators haven't digested what the alternative is and its implications. It requires a regulator to approve a wholesale cost pass-through to customers. This requires decisions on whether you allow only spot prices, or contracts also; whether you allow a day, week, month, year, five years, or fifteen years ahead; what the proportions should be; and whether retailers or incumbent suppliers can own their own generation, and if so, how much. These are significant decisions that impact customers, generators, and the wholesale market. If regulators could make efficient decisions without political influence, would we have pursued deregulation at all? These core decisions are best made by the market participants in a properly functioning market.

Even where markets are operating successfully, questions about who takes the risk are still unanswered. It is beginning to happen in the United Kingdom and somewhat in Texas. However, they strongly characterize the markets in the Scandinavian countries.

In Sweden, over 20 percent of the residential customers have switched to another supplier. Another 20 percent have negotiated a contract with their own incumbent supplier. All these customers, 40–45 percent, have chosen a fixed-term contract on specified terms, they've all negotiated a contract. There's an enormous range in these contracts. They include spot pricing. Ten percent of Norwegian residential customers have incorporated that. Fixed price contracts vary from three months to five years. Customers themselves are actively deciding how much risk they want, and for how long. Their views vary enormously. Some don't want any risk at all; some hedge for three years; others for three months.

These developments will make a significant difference in the way these markets operate. The proposals for regulation as an alternative to that cannot grapple with that problem.

COMMENT: There's an interest in fostering sticky relationships with customers. Stable customer relationships can allow for long-term generation contracting, – something we're interested in. Municipal utilities with aggregation gain all these benefits.

Not only do we need reasonable assurance of price from generation; we need it for our all-in price over an extended period of time. This requires long-term rights because you need constraints on your transmission costs, as well as your generation costs. I'm pleased there is interest in longer term FTRs. We need to put together generation and transmission for customers in these RTO markets.

QUESTION: Who's going to build generation in this environment? We heard earlier about the turnover in power plants. But those were existing plants, purchased by equity investors, probably in a somewhat distressed situation from the sellers.

Alternately, in eastern PJM and parts of New England, we'll have to build generation capacity from the ground up quite soon. Given that the retail market isn't ready to extend long-term contracts from aggregators, how are we going to do that?

PJM has developed its own version of New York's locational pricing, locational capacity requirements, and capacity demand curve. PJM calls it the Reliability Pricing Model, and it is capacity market re-regulation of sorts. Is that a reasonable way for PJM to go as a measure to get us through the next ten years,?

ANSWER: Most of the problem right now is timing; secondarily, it's information. Financial markets do provide for investment. But they have to do it in a stable environment in which people are accustomed to working in a particular way. Some characterize financial markets as innovative but actually, they're quite conservative. Nobody's gotten comfortable with development financing yet. If you left it up to the market, they'd have to finance the first three years of the development cycle with equity, which is expensive. However, after that, once could get a long-term contract and take some equity out of the plant.

I'm not up to the full policy decision on that. But I do find RPM and ICAP troubling. RPM is more troubling because the central planner decides where something's needed; holds an auction; then commits to buying from the entity that wins the auction. They're allowed to allocate that cost to customers. That's what regulators used to do ten years ago. It's just status quo.

ANSWER: Let's consider risk management. In retail competition people jumped in to serve load, but they didn't manage the risk consistent with what their customers want to take on, the most fundamental thing associated with serving that load. There's a disconnect. An important role has to be managing risk consistent with customer needs. This involves something other than totally unhedged spot prices, even for industrials. When prices go up, and they have to shut down and lay people off, it becomes a political problem. There has to be forward contracting of various lengths, and this requires new entry. Who will write those supply contracts?

If spot prices are dulled and capped, then market actors know they can buy energy out of the spot market safely and they may not hedge by building the physical plant or going upstream. Then the spot market runs out of energy because everyone free-rides, and we don't build enough. If we had more sharply-priced spot markets, and requirements that load-serving entities hedge upstream, contracts and commitment of capital would be there.

COMMENT: The most costly unhedgeable risk is regulatory and political. It's no coincidence that the greatest lack of investment is in areas where regulators are unpredictable and interventionist. Certainty and clarity are needed to get a low cost to capital. This is certainly a capital-intensive industry. Thinking about the rules carefully before you implement or change them is important for private investment to operate effectively in an open market.

QUESTION: In California, there is a workable system that provides investment in energy efficiency while being compatible with wholesale and retail competition. This prioritizes investments in energy efficiency before investments on the generation side. It affects anyone providing retail service, whether it's the incumbent utilities or the energy service providers. Energy efficiency is funded through a public goods charge on the distribution system, so everybody pays.

For many years, this funding was done either every year or every two years, which made it difficult to integrate the energy efficiency piece into supply needs. Last year, the Commission adopted ten-year energy efficiency savings goals for investor-owned utilities, and moved toward a three-year funding cycle to increase stability. Further, utilities will now be major administrators of these programs.

In the retail competitive market, the suppliers were not really set up to offer energy efficiency. You can't think of energy efficiency as a commodity product to be delivered the same way as power. Especially if you're dealing with customers who have one-year or two-year contracts, the energy efficiency model doesn't fit well into that. It takes a while to work with customers, for them to figure out what they need. If they have to make an investment, they have to persuade upper management to invest in energy efficiency. So you have more stability by running most of your energy efficiency programs through the utilities. They've set up a hybrid; 20 percent of funding is done through competitive solicitation of third parties who offer different programs that are then paired up with retail customers.

On the commodity side, California is in a period of suspense on direct access, which is retail competition. About 15 percent of our retail load is on direct access in the retail competition market. That's very little on the residential side, but quite significant for industrials. California law prohibits the Commission from restarting the competitive retail market. An initiative against this has successfully qualified for signatures. If there is a special election this November, it will be on the ballot. This would roll back California from any retail competition. It wouldn't abrogate contracts that are in place as of the end of 2005, but it will prohibit any new contracts.

Finally, consider the dynamic between short-term and longer-term contracting that we started off with in the California market. We had our utilities sell off much of their generation side and enter into spot market purchases for their bundled customers. The California crisis, with the spot markets on the wholesale side being driven up, led to a lot of our problems. Recently, the Public Utilities Commission has gone to the other side, directing utilities to enter into long-term contracts to secure pricing stability. We're back to detailed regulation on almost a micro basis in terms of spot markets, five-year contracts, ten-year contracts, and longer contracts, which is somewhat ironic.

So, can we set up the proper incentives for entities offering retail competition and retail supplies to enter into longer-term contracts? How can companies deal with this anomaly if most of their contracts with retail customers are between one to three years? How does California ensure there is adequate investment in power plants to have the reliability that we want?

COMMENT: We have only a small fraction of adults over the age of 18 who vote, yet we still go to the time, expense, and energy of holding elections. Retail choice is not too different from that. Over 90 percent of our customers know they have a choice, yet 25 percent have switched. Those who haven't switched are not ignorant. They may have consciously decided, for one reason or another, to stick with their incumbent rep. This occurs even though the best available competitive offer is less than prices the day before deregulation -- less than. People have knowledge. They make choices, and some of those choices are not to move.

Let me address the environment. Since we deregulated the wholesale market, we've had about 20,000 megawatts of highly efficient clean gas-fired generation come into ERCOT. None of that is in rate base. It's all investor-owned merchant capital. There are dramatic reductions in heat rates. There is retirement of old dirty plants, dramatic reductions of NOx and SOx in the ERCOT market.

When one of our formerly regulated utilities decided to sell some generation units, initial bidding had over 25 interested legitimate parties. The winning bidder ended up paying a premium above the stock price. There are people interested in putting money into the market because they have a degree of comfort with the design. This occurs despite problems such as the thousand dollar cap or the $300 embarrassment cap which serves to act as a $300 cap on offers.

ANSWER: In our system, larger users who stay on default go hourly. Most of them shop. All of our customers can shop at every level. We've removed a lot of barriers. There's very little aggregation except for some of the bigger and medium-sized users because the retail customers get wholesale prices at retail level. There's no effort because they can't do any better. It is plain vanilla service for the retail customers. They do have different needs and wants. We're doing the best we can to provide reliable service and the lowest possible rates with our wholesale auction.

ANSWER: Every state has to craft something that fits its particulars. The model I described earlier would bring customers into the competitive market effectively over a period of years. Once there, many would be sticky and would stay with their incumbent, if they were serving them adequately. More of a minority would switch around. They'd all be served by competitive suppliers. It requires political will to do it; leadership from a legislature and a governor and regulators.

QUESTION: I was struck this morning by the sense of wistfulness about the failure of retail competition to deliver its hoped-for benefits, at least in certain states. If there are costs in making choice available, is the conundrum true for every state, and would you have the same prescription for every state?

ANSWER: The conundrum, meaning whether to try to push forward with a reform agenda that would move competition further to the smaller customers? That's something that any state engaged in restructuring is wrestling with. Many states are asking whether they should bother with retail at all. States involved in the deregulation process are wrestling with that because they find themselves stuck halfway off the ledge, so to speak.

QUESTION: Is there a problem with half the country being in one position and half in the other position? We used to hear regularly that this country cannot stand half slave/half free, half retail/half traditional. Yet that's where we are.

ANSWER: It's certainly inefficient to have a patchwork of states regulating in different ways, but inefficiency is not the same as injustice

QUESTION: If it's inefficient, is there an opportunity cost involved, and if so, for whom? The customer? The states that have already gone retail? The transmission system?

ANSWER: Well, states will not give up their rights. The country is stuck with fifty different decisions about retail competition. That's just the way the system works. The harder dilemma is that the impetus that drove fifteen states to move forward on electricity deregulation came at a time of innocence and passion and enthusiasm, and a willingness to take risks. With ten years of hard experience, it's harder now for any new state, let alone the states that have started, to continue that reform agenda. They all know the price to be paid for mistakes much more vividly than before.

The need now for an incremental process makes sense. Innovations such as finding demand for choice, interest in various products from middle-size customers, and regulator regimes that allow suppliers to deliver and respond will be an important next wave. After that we're going to have wait some time before we can go to the further wave of retail. External circumstances – for instance, oil prices that go from 50 to 100 dollars a barrel -- could change the situation. For the moment, we're stuck with incrementalism. We lost the opportunity for revolution that we had seven years ago.

ANSWER: This will not happen overnight. The Norwegian market was one of the first to deregulate in the early 1990s. Having multiple states experimenting in different ways may not be bad for retail competition. One can't expect customers to change overnight, nor would one want that.

QUESTION: I heard a suggestion of removing wholesale price caps, but first, or at least simultaneously, protecting residential retail customers from volatility. That's probably the foundation for a very long conversation, but it strikes me that there are some mutual interests there.

ANSWER: The risks need to be in alignment. If residential customers want to be in the spot market, and have indicated that in some fashion, and they'll take the results, then they should have that option. However, we need to do a better job of communicating the fact that they actually are taking risks so we don't have people taking risks but don't know it, and then complain about it after the fact.

QUESTION: The other concern is the assertion that a free market can only work with involuntary assignment of customers. How is this good public policy from a residential point of view, given the already demonstrated disinterest in retail markets or taking on that kind of risk, and the failure of even successful competition to provide innovation or control prices?

ANSWER: You're describing customers who are captives of a monopoly provider as free? They don't get to choose their monopoly provider.

COMMENT: Is group slamming the answer?

ANSWER: Government has made decisions to organize customers in one way. With a certain degree of thoughtfulness and political will, they can decide to organize customers another way. I don't accept the characterization that one is basically voluntary and the other is involuntary.

COMMENT: Well, Massachusetts has a theoretically open marketplace. There's one territory where there is actually one competitor. There has been zero choice outside of the one aggregation. Those folks aren't captive.

ANSWER: They are indeed captive because we've told them, theoretically and legally, that they have a choice, and there is none. We have not delivered on that promise. We haven't provided the infrastructure in order to be able to get choice. You can't expect retail marketers to get over the barriers that they face and serve customers on a wish and a prayer.

Session Two. Transmission Expansion in Restructured Electricity Markets.

Participant funding, locational pricing, transmission rights, reliability investment, and many other issues under discussion in the United States arose in the restructured electricity market in Argentina. Case studies reported that, contrary to a widespread perception, there was a remarkable degree of success with transmission expansion determined by participant funding and participant decisions instead of by regulatory mandate under a system with locational pricing, even in the absence of financial transmission rights. How does this experience contrast with other merchant investment models? What lessons for the United States follow from this experience? Would an adaptation of the Argentine "Public Contest" model be appropriate in the United States? How would such adaptations compare with the developing frameworks for transmission investment in the context of open access?

Speaker One

The question that I'm posing today is whether the conventional wisdom is correct, that regulation is the best way to deal with investment and pricing in monopoly networks. In Argentina, transmission investments are decided upon and paid for by the users. That is a different approach. How well does that approach work, and what are the implications for policy?

In 1992, Argentina decided to reform and privatize their electricity industry. They restructured it in a similar way to the United Kingdom and other countries. One unique provision was that major transmission expansions weren't the responsibility of the transmission company or the regulator. Instead they developed a *public contest method*: a specified set of users for each investment had to make proposals for that investment. They voted on it and provided there was a sufficient majority, it would go ahead, and they would pay for it. The expansion investment was then tendered for potential constructors and operators to bid on. There were other methods of expanding transmission capacity also. If you had one, or a small number of users, that wanted a connection to the grid, or minor expansions under a certain specified cost, they could pursue it on their own. The general impression of the Argentine experience is that reform worked well in general; lower costs and prices, better service, more investment, generally a success.

The major caveat is that transmission investment arrangements did not work well. The main reason for this – probably the only reason -- is that for several years there was a delay to a much-needed investment in Argentina. This was the "fourth line" from a generation area in Comahue to the main load center in Buenos Aires. Economists and others have argued that failures occurred because the allocation of user votes reflected their usage amounts in the system, not the benefits they derived from it. They also argued that the major beneficiaries were the consumers in Buenos Aires who didn't have a vote at all. Finally, they pointed to transaction costs, which prevented users from organizing, free-rider problems, and a lack of property rights. Some have argued these issues could be fixed. However, most concluded that it was not sensible to have investments assessed by users instead of regulators.

Why did they adopt this policy in Argentina? Before privatization, there had been strong political pressures which led to excessive transmission investment, as well as other areas. The fear was that regulators would continue excessive and inefficient transmission investment, given the interests of the transmission companies. They believed that users would provide a check on this influence. Market designers need to evaluate a set of arrangements against the practical alternatives, not against some ideal benchmark. From their point of view, the practical alternative was inefficient regulation.

The fourth line is a big issue. The Comahue generation area is in the middle of the country on the left side. Traditionally, hydro systems were there, and lines were built going northeast to Buenos Aires, which is almost halfway down the country on the right-hand side. Three lines were already built to service major hydro stations in Comahue. Everyone expected a fourth line, given the generation that was under construction.

The congestion on that corridor gradually increased. There were local nodal prices in operation, so the generators got low prices in Comahue whenever the line was congested. That's why they wanted more generation. A provision allowed congestion revenues to be applied toward an expansion if it reduced the congestion on that line. In September 1994, three generators proposed to build this fourth line. They proposed a company that would do it at a cost of $58 million per year for fifteen years. There was a public hearing, and 50 percent of the voters were against it. This was a disaster because it had been assumed that the line could and should be built, and here was the system evidently failing. The generators then worked for certain changes in the regime. In May 1996, they put up a new proposal and over 80 percent voted for it. They capped costs at $44 million a year and budgeted congestion revenues at another $11 million. So we're talking about $55 million, just a little less expensive than last time. The project went ahead. Bids were taken in 1997. The incumbent, Transener, was pushed hard by several competitors, and the bid went down to $24.5 million. If you add the $11 million in congestion revenues, it came in at $35.5 million. The line in operation by 1999.

What does this tell us about these allegations of system failure? Was it a serious delay? Well, it wasn't very long, just over a year and a half. Those involved in major transmission investments know that's not bad.

Was the measurement of usage rather than benefits a problem? Well, you've got to find some way of measuring benefits. And usage is as good a way as any. Otherwise, you're into a very subjective set of judgments.

What about the exclusion of major beneficiaries in Buenos Aires? Well, if the line hadn't been built, generation would have been built in Buenos Aires. So the question wasn't whether they were going to get generation; it was, how should it get there? So it wasn't a big issue in Buenos Aires.

Were there transaction costs? After the no vote, generators organized together. They worked harmoniously and brought about the investment; quite the absence of transactions costs.

Were there free-riding problems? Well, these were not so bad. These guys were not putting up the money; if they didn't use it and others did, they lost out. Whoever used it at the time paid a usage fee. So free-riding wasn't really a problem.

The reasons given for the delay in the Comahue line are not accurate. So why didn't it go ahead? Was it really economic? Less than the optimal amount could come from Comahue, and those generators got a lower price than consumers in Buenos Aires; they had to pay the price in the rest of the system. Let's estimate the benefit. Congestion averaged about $30 million a year over this period, and the expansion in capacity was about a third. So the value of that extra is about $10 million. The system is expanding; maybe the value will be increasing. Let's take an optimistic view of the value; put it at $10 million. However, the value varies, depending particularly on rainfall, and might range from about $8–17 million. The regulator's economists had put the value of this extra investment at about $6 million. The new estimate is two to three times what the previous study had made. And the previous study was what everybody relies on in saying the system didn't work.

I have explained where the value came from. How does that compare with the costs? The proposed cost was $58 million the first time. As a result of competition, it got beaten down to $35.5 million. This is still twice the most optimistic value that you could put on the expansion. Here's the conclusion. This was not simply an economic expansion of the transmission system. For instance, if you could adjust this system, would it be more economic to build a transmission line from Comahue, or to generate in Buenos Aires itself? With the new gas-fired generation coming on, it was cheaper to transport the gas to Buenos Aires than to transmit the electricity. The reason this line didn't get built at first, was not because of a process failure, but because it wasn't an economic line to build. The process identified this, and highlighted it for further discussion.

The problem then is to explain why it did get built if it wasn't economic. The answer is that the private costs and benefits differed from the social costs and benefits. For example, there were generators there who had a strong interest in removing the transmission constraint because they wouldn't be losing congestion revenues. The people who benefited from those congestion revenues weren't well-identified and able to vote. Second, the use of these funds could be considered a subsidy, or at least one use of funds for another purpose.

Over time, the costs went down sufficiently as a result of more competitive bidding. The benefit from the Salex contribution went up, and the benefit of building the line went up as well. It gradually became profitable to vote for it from a private perspective.

What else do we know about the way the system worked? With the exception of that line, it seems to have been accepted as a sensible method on the whole. There were some problems with provincial regulators instead of national jurisdiction. It worked well as one of several methods. About 9 percent of the transmission projects over the next decade used this public contest method, but they accounted for about two-thirds of the value.

It promoted economic decision-making. It enabled economic investments to go ahead, and stopped uneconomic ones. It made better use of existing lines which were in surplus capacity at the time. There's no doubt the alternative regulation regime would have been less satisfactory because they would have yielded to the pressure to build new lines. In fact, they would have promoted this. The regulatory body was the main critic of this method, and the prime advocate of more lines being built.

Let's examine how these projects are put out for competition and construction. I have specific data for only five projects, in addition to the fourth line. In each of those, there were two or three bids. They were all won by new independent transmission companies. Competition was effective there. In the fourth line, there were four bidders. They placed a total of thirteen bids between them, because they were so determined to get the contract that they offered many variants. This included new technologies that hadn't been used yet, but offered the prospect of lower prices if the bidders wanted to accept it, which they did. As an indication of efficiency, the cost per kilometer roughly halved over the process from the onset of privatization to the building of the fourth line. The process turned out to be very successful. This process whereby the users decide worked well overall. It hasn't yet been tested on major projects that do seem to be economic, but it has been tested in other respects.

The process problems are not as significant as has been believed. For example, the vote allocation, the free-riding, the transactions costs were not nearly as problematic as some thought. There is scope for improving the method. Clearly, if an uneconomic project can get through, something should be reconsidered.

Currently, this policy is still in existence, but it's superseded for two reasons. Political pressures have increased to construct new transmission lines, even though they weren't economic. To do that, they needed another method. The alternate process was a variant of subsidies, where the government offers subsidies and bidders pursue specified lines with subsidy packages attached.

However, the macroeconomic crisis occurred before this new policy could be assessed. The crisis was a disaster; devaluation took place so that the currency was worth about a third of its previous value. Prices were frozen at that low level in pesos and this has discouraged anybody from investing. The system is in limbo, but it wasn't because it failed to deliver economic expansions that it no longer operates.

In evaluating transmission regulation arrangements, the debate among economists has centered on the question of whether user or merchant methods of investment are comparable to regulation in terms of economic efficiency. And if anything, my studies of Argentina, and also Australia, suggest that the merchant modes have a better record against regulation in this respect than is sometimes suggested. What becomes apparent in all countries is that non-economic considerations are important. Policymakers get interested in a variety of goals, such as redistributing income, providing work in certain areas. In Argentina they call this the federal nature of transmission investments.

Do we think of these as legitimate social goals, promoted by an elected government? Should the framework facilitate the achievement of these goals, or do we think of them as uneconomic and inefficient political issues which should be resisted? Should we choose the regulation to try to resist these pressures? These are important questions that need to be resolved. If there are non-economic aims that are legitimate, are we stuck with regulation as the only method of achieving them, or is it possible to build them into the process as an explicit subsidy. Such subsidies can be bid for as a way of enabling merchant or user participant methods to provide non-economic objectives. That is an aspect of the debate that economists haven't entered into yet. It's worth more thought.

Speaker Two

I was part of this fourth line thing from the beginning. I believe this was the first to use LMP. In late 1992, Argentina implemented locational marginal pricing with congestion pricing. I was involved in a bid for a hydro plant in western Argentina in 1993. There wasn't price history. There wasn't very much data, only the data that they wanted us to have. There were no market rules in English. They were in Spanish. We had to translate those, and try to understand as best we could. Before we put together the bid, we had to pull all of our information out of these wordy documents in Spanish. The people in that environment were being truthful, but not helpful.

I might be the world's first power market analyst to have been badly burned by LMP. Nonetheless, I learned a lot of things, and came away believing in LMP. One is the importance of marginal losses in LMP, which we still don't have everywhere. Argentina is a system with very long lines. Some of them are radial. A lot of hydro. There are non-power uses of the hydro; not so different from the western United States, is it?

The meaning of congestion in an LMP market was something that I learned then. The old meaning of congestion in the physical bilateral markets is still around. In an LMP market, it's a state of having active constraints. You've dispatched, and you've resolved congestion, and there are no overloads. In the physical bilateral markets, congestion is associated with overloads and having to address them.

The implications of congestion pricing confused us. As a power engineer, I understood how to do marginal losses; they made intuitive sense to me. Congestion pricing didn't. It's painful if you don't understand it before you invest the dollars. Despite this I came away from the experience with a belief in LMP. The more I looked at it, the more I realized it is right.

Like LMP, the more I thought about the way they built transmission the more I liked it. Transmission enhancements can be brought into the market by market participants responding to price signals. LMP is necessary but is not sufficient. FTRs can help, but they are not enough to bring transmission. More than LMP is required, and this is what Argentina had.

The process in Argentina is very crucial. They assign specific responsibilities to the different parties in the market. Is this participant funding? Basically, for Argentina this is like applying for approval to bring a transmission line into the regulated system. Beyond that, revenue requirements will be allocated to the people who proposed it, and others that may be benefiting from it. The line ends up with a good guarantee of cost recovery, so financing is easier. We've seen it done, even when the line wasn't economic.

The proposal and approval process is important. Let's consider the responsibilities of the participants first. Argentina has a major transmitter similar to ATC. The transmitter is responsible for maintaining the availability of their assets and their revenue flows from that. There are also independent transmitters. It can be the same actor as the major transmitter, but competition in transmission construction and ownership is possible. If competitors come in to build the lines, they may operate and maintain them. They have responsibility for the availability of their assets, like the major transmitter. The users of the network -- generators, large users, distributors -- are responsible for proposing expansion projects, and the onus is on them completely for that. They're also responsible for the revenue requirements from the project.

Consider the network also, which is very far flung. Imagine Alabama Power Company with 15,000 megawatts and 6,000 miles of 500 K looping around in it. That's how different this system is from the kind of thing that we're used to. That was part of the problem.

The process is laid out clearly. The first time it occurred, there were problems, and they have straightened them out since. First, generators or distributors have to suffer some sort of cost condition. There are other ways than just congestion but congestion was the major issue, especially in Comahue. The first requirement was to create a generator consortium in Comahue region to reach consensus about whether it was our responsibility to get it done. Then the consortium makes a proposal that includes a constructor and a schedule. It includes revenue requirements, out to fifteen years in the future. It is submitted as a request; in other words, here's a line; here are beneficiaries proposing it; here is what it will cost, and what we'll pay for it, along with other beneficiaries.

The ISO then identifies the beneficiaries of the project and applies the golden rule: is this a good project for the whole system? They're probably fairly liberal with that. Beneficiaries are people whose prices will rise if they're generating, or prices will drop if they're buying. It's that simple. They must agree that the project can go forward and they have to pay. The fixed revenue requirements bid by the group are allocated by pro rata share to these beneficiaries. If the project is beneficial to the system, and 70 percent of the beneficiaries agree, the project can go forward. It's officially approved. We don't know yet is exactly who's going to built it but it will be in the regulated system.

The project is then put out for competitive bids, to look for alternate constructors or perhaps alternate specifications. In the end, the project may be built, owned, and/or operated by an independent completely unrelated to the original consortium. This occurs because they bid a lower price. This is a better outcome even for those people that proposed it.

Notice in my documents that in one configuration we had 4,000 megawatts of capacity and in another we had only 2,600 megawatts. Numbers were very fluid, and you couldn't trust any that you saw.

The fourth line added by the Consortium connected some plants that were way out into the market. Was that economic or not? It seemed obvious that this is needed. These people have been planning this thing forever, and look at all the congestion. But we didn't have the time or the computers or the models to analyze that on the spot. We had to assume that we understood these problems. In essence, we group-thought our way into this power plant. Ultimately, this was not a coherent, optimally-planned system at all. This was built by government. It was built by special interests.

In this process, the people who do not benefit from a transmission line do not have standing in its approval. Construction is procured through a competitive process. Recovery of revenue requirements by the transmission project owner is contingent on availability performance only. The owner doesn't care whether prices are up or down, or whether there's a price differential;

they are paid by keeping that thing in the air. This behaves like regulatory protection. The projects can be financed on that basis because cost recovery is manageable. No other special incentives are required. Nobody knows what the return on equity on this project is. They didn't have to give an incentive; didn't have to bump it up because this is transmission. And that's a big benefit there.

Speaker Three

I will speak a little bit about the United States, and in particular, the Southeastern region and generator interconnection. There are 17,000 megawatts of new merchant plants on the transmission system located in Mississippi, Arkansas, and eastern Texas. When many of these generators located on this system, transmission was not their first consideration. There are many pipelines running through the service territory. Some invested in optional upgrades, and they all invested in the interconnection facilities, they weren't really concerned with getting energy to a load somewhere. In fact, many of them did not know which load they would serve. As merchant plants, they simply wanted to interconnect to the system, and assumed they would have transmission capacity to deliver the goods.

Further, our transmission reservations have increased from about 30,000 reservations in 1998, up to about 100,000 in 2004. Schedules have also increased dramatically from about 30,000 or so in 1998, to over 160,000 in 2004. We expect increases to continue.

So we've got this tension. Our grid was historically designed to serve the native load, and some economy interchange between utilities. And now, we have almost twice the generation that we had five years ago. How do you accommodate new construction and transmission expansion?

In Session One, there were discussions about one of the benefits of restructuring, which was shifting risk from customers to suppliers. This was discussed in the context of generation facilities. But why wouldn't that apply to transmission, as well? There needs to be some discipline on transmission expansion; otherwise, you end up with an uneconomic fourth line. We also need price signals so that generators know where to locate their facilities. That's why the participant funding concept is useful.

Proposals have included locational marginal pricing of financial transmission rights. This provides a benefit to customers that upgrade the system by allocating a financial transmission right to them for thirty years. There is a long-term right associated with expanding the grid. However, that effort was suspended in our region. Now, an independent coordinator of transmission proposal is in the works that includes the beneficiary paying for transmission expansions.

Beginning in 1996, I've been involved in efforts to get something like an RTO running in our area. A current proposal is not an RTO, but does provide benefit to customers because it is more transparent and independent. The original filing occurred in April last year. Originally, it was mostly oversight but a recent petition included some transfer of functionality. The FERC approved it with conditions in March. There'll be a 205 filing on it soon. The group will calculate available flow gate capacity. They will administer transmission, expansion, and pricing policy.

The base plan project includes projects to honor long-term firm transmission commitments to both point to point customers and network customers. They'll accommodate load growth from existing resources. It will also include projects to maintain reliability. Those are easy to identify. There's no identification of users or benefits. The Independent Coordinator of Transmission (ITC) will independently consider NERC and SERC rules and determine what projects are required.

Supplemental projects are basically any other project. That includes new point-to-point and network services, as well as upgrades required to accommodate those types of services. This would include generator interconnection. Under

FERC's Order 2003, there are three levels of interconnection now. These are NITS and energy, and a middle category, the Network Resource Integration Service. They have delivery rights, but don't have to pay congestion. Those delivery rights can be made available by transmission investments. They would be supplemental, as well. Other projects could be proposed by various entities to reduce congestion, and for other economic purposes.

Currently, cost recovery for point-to-point service would assess the embedded rate with the project included, or the cost to the project, and charge the customer the higher of those two categories. For network service, it's different in that there's no new revenue associated with a network customer, just changing resources. If a customer wants to get integrated at an ERIS or NRIS level, they would pay for the project itself up front. NITS customers trying to integrate a new network resource would do that also. Those projects would be directly assigned or participant-funded.

On transmission rights, LMP FTR considerations are not in the ICT proposal nor are they expected soon. They would make some of the financial transmission rights aspects of the offering easier to accommodate. But certainly, they'd get whatever right is associated with the service that is requested. For example, if someone wants to be a network customer and have a designated NITS resource, it would be considered. If there are upgrades required, they would be completed. Ultimately, they'd have congestion-free rights to deliver that energy to their loads.

The proposal includes congestion protection. Included is a weekly procurement process that requires more time than I have, but one output of that process is a congestion rate that will be charged to any NRIS or ERIS resource that transacts on our system. However, if you've upgraded a facility, you will not have to pay congestion across that facility. Another component is financial compensation for customers that upgrade a facility in a lumpy fashion. For example, if a customer pays for 100 megawatts of additional capacity on a flow gate, but only needed 50, if the remaining 50 megawatts were sold on a long-term basis, those funds would go to the customer that upgraded the facility. Much of these details will be finalized soon, and some are in flux. Customers are not satisfied with just the benefit of integrating, access to different markets, or access to cheaper generation. There needs to be something in addition.

Speaker Four

I want to consider how you do transmission expansion. How does one make the investments and solve the problems discussed earlier. Second, given electricity restructuring, how can these mechanism be made compatible with the broader goal? This morning there was some optimism about success. I'm not so confident about that. It could be quite painful along the way.

Transmission is in competition with other things. If you have a centrally-planned process for making transmission investments and you socialize those costs then you have to ask whether it should be the same for energy efficiency; or for generation in Buenos Aires, etc. The big money is in the focus on incentives for investment and that's a large concern. Operating efficiency benefits, while not trivial, are not the main focus. Markets don't seem to forecast better through the utilities so forecasting is not the issue but rather that risks are distributed in a different way. That's what creates different innovations. The market does different things to deal with risks, even though it can't necessarily forecast particularly well itself.

There is a tension between central coordination and central procurement. If the market can't make all decisions, how do you put market and non-market components together to make them compatible? Successful market design is a real problem for these transmission investments. Last week's white paper from the FERC staff, argues that FTRs may be necessary, but they're not sufficient. Well, that does mean they're necessary.

FERC is asking if the market may sometimes fail to create an incentive to invest economically beneficial projects, especially with substantial economies of scale. This can result in transmission market failure. One of their schematics suggests that the market clearing price, after the fact, is too low, even though the benefits before the fact look like they're very attractive. I don't wish to argue whether there are market failures that require intervention. The point is to focus on the nature of the market failures so everything isn't ruined. If the only problem is that there's a market failure and the RTO should have built this, well, then build that. It may mess up other things, so you have to think about how these pieces actually fit together.

How is FERC addressing the boundary between markets and mandates for transmission investment? I argue that the SMD had it basically right. It addressed merchant investments, reliability investments - which would be relatively limited in scope, problems of economies of scale and scope, and mitigation of free-rider incentives. The ideas were basically right. The question is how to implement it consistently with the rest of the market. Further, how well is FERC doing in practice? Decisions are accumulating that are inconsistent with the description of theory in the SMD. They are making decisions and implementing systems which are undermining the broader purposes of SMD. This is because they don't have a way to delineate the boundary between markets and mandates.

The PJM mandates for economic investment are a good example, and I have quotes in my presentation from their Regional Transmission Expansion Planning Protocol. Their process starts with economic analysis, and then to find investments that are economic but unhedgeable. A waiting period is used for the market to solve the problem for a short while but if they don't, then the regulator -- the ISO -- mandates the investment and socializes the cost. Well, what is unhedgeable congestion in a market? It is an oxymoron. It replaces the market with central planning, and this will lead to thinking about subsidizing everything else.

In its transmission cost allocation process, NEPOOL is similar; virtually everything of interest gets classified as a benefit for everyone, and then we socialize the costs. Explain this to people in Maine who are paying for transmission to take their power away to other customers. The implementation of these ideas in the SMD are not consistent with the rest of the market. The PJM web page shows some of these calculations. They show several examples with good ratios of costs to benefits. Why isn't the market doing it by itself? Why does PJM have to do it? It's a hard problem.

This is not the only problem -- ICAP markets are another -- but it demonstrates the slippery slope problem. How far do we slide back toward central planning? I'm suggesting the we structure the interventions so there's a clear boundary between what will be mandated by central planning and what can be done by the markets.

One suggestion is that investments where people would be compelled to pay under regulation would have to pass a two-part test, not just a one-part test. The first test would be economic justification that shows that aggregate benefits exceed aggregate costs. This is a standard social welfare calculation. There's nothing fundamentally new there. The second test is a market failure justification. What is special about the investment that justifies a non-market process? Is it large and lumpy enough to affect market prices and create economy of scale problems? This would be a new test targeted on market failure. In principle, all the information needed is produced by the initial cost-benefit calculation. It is not a hard question to answer.

The PJM definition of market failure is not that it's large and lumpy, but rather, that the market has failed to do what the central planner wants. This is a dangerous perspective, because it leads us back to problems we were trying to avoid. If central planners or regulators know what to do, then we should do it. If this is true, then what's the need for electricity restructuring in the first place?

Argentina provides some of these lessons. First, there was a lot of transmission investment under this system. Nobody even noticed that it was going on. Outside of Argentina the fourth line problem was the only salient issue. Many people got the story backward.

So, I am confident that transmission can be built under these kinds of rules, and compatible with the successful market design incentives. Beneficiaries could be defined properly, participant funding could support a market, and FTRs would be an enhancement because it was done without FTRs in Argentina.

What would it look like in the U.S. context? We'd have a coordinated spot market, locational marginal pricing, and FTRs. This would certainly allow for expansion of transmission capacity by contracting parties. If people voluntarily want to do it, they could go and do it.

Having minor expansions with some dollar cutoff at the initiative of the transmission company is reasonable. You don't want every decision made through these processes. The public contest method has merit for major expansions. We should be looking at it more closely. You would still apply the Golden Rule test. That's not necessarily perfunctory, and it identifies the beneficiaries.

The 30/30 rule, where 30 percent of the beneficiaries must propose it, and no more than 30 percent oppose acts as the fundamental decision constraint. Costs are assigned to beneficiaries with mandatory participant funding. Auction revenue rights or long-term FTRs, along with the payments that have to go on, are similarly allocated. The 30/30 rule can be conceived of as an alternative to the market failure test, or as a complement.

We have to worry about how we overcome market failures. The markets will never be perfectly designed. We don't even know how to do it in theory, much less actually implementing it. There are problems associated with lumpy decisions and market power and unpriced products, and other issues. However, the solution can't undermine everything else that you're trying to do. That's the concern for transmission expansion; ICAP markets are similar. The Argentine experience provides empirical support for the viability of a market. It suggests an approach for limited central procurement that overcomes market failures without overturning the market.

Discussion

COMMENT: Clearly, a participant funding system, particularly a voluntary one, will not normally lead to the optimal amount of transmission investment. The first speaker gave an excellent example of the difference between private and societal benefits, and you can construct cases where participant funding will lead to over-investment in transmission because the people who benefit get the say, and the people don't benefit aren't able to block it.

When we've tried participant funding in the U.S., it's led to under-investment. They tried to rely on market transmission projects in PJM, and not a lot of transmission got built. As soon as economic planning was introduced, many projects with significant cost-benefit ratios were being identified. If participant funding was working, why weren't these projects being implemented before we introduced an economic planning process?

Second, the Argentine example is not pure participant funding; it's a hybrid system. Some of the free rider problems in participant funding are addressed by the lack of a blocking threshold. Once 70 percent say they want it, it is allocated to everybody. Thus, the free-rider problems that you might get in pure participant funding – e.g. in the United States -- have been addressed. The characteristics of the Argentine system mean that you don't see some of the problems you may see in other systems. It's a radial system. The difficulties of allocating cost beneficiaries on a mesh network, or conflicts of interest from common ownership between generation and demand aren't prevalent in their system.

Third, to delineate between a regulated approach, and what can be done by the market. There's a simpler line to be drawn, which is to say transmission should be planned on a regional basis. Draw the line there, then treat everything else in terms of generation demand as a market. It's not as theoretically pure as the fourth speaker's suggestion, but it is a pragmatic way forward. The experimentation with market transmission in the U.S. has been a disservice to the wider success of the electricity market because lack of transmission investment is leading to real market problems. These include insufficient competition, leading to price caps; RMR contracts; LICAP markets; and the like. It may not be the best model theoretically, but treating transmission as a planned regulated market facilitating entity and allowing the market to compete over that is workable.

ANSWER: Participant funding can lead to less-than-optimal results, but so can anything else. I have studied systems involving some market involvement in Argentina and Australia. It is clear that the regulated approach leads to systematic and substantial overinvestment. That is less optimal than the participant or merchant approach. Argentina still has to get over some problems.

I wasn't sure what you meant by the hybrid model. Certainly proponents and others pay as well, this is true. In effect, this system seeks permission to tax everybody, and you have to have a sufficient proportion in support to do that. The Argentine network is largely radial, and that makes a lot of these decisions easier. They have enough problems without worrying about dealing with a meshed system. They'll be able to cope with it in Argentina when it happens. The sub-transmission systems just below the main transmission level exhibit a more meshed structure. The same framework is applied there. Despite this they kept the rules as they were, and simply allocate at a fine level of detail the numbers that it gave. You could devise another system but this has proved adequate for the users in Argentina for a more meshed system, as well as a more radial one.

ANSWER: The commentator's point is a legitimate one. There is no perfect solution to this problem, even in theory, much less in practice. Where can you draw the line? This is probably context-specific. For instance, in the United Kingdom you could have a rule that says a company invests in transmission, and they do whatever they do under these rules; we don't worry about anything else, and we're just not going to talk about anything else. It would be a sharp dividing line. Can you imagine that happening in the United States? Unlikely. The problems here are more of the "slippery slope" issue. Rainbow Valley is an example (a transmission line in Southern California). They went through all the arithmetic and as soon as they finished, everybody else got into the queue. There was efficiency generation located here, generation located there. They went to the Cal ISO and the regulators, and soon they were starting a big RFP process for different options that could substitute for transmission and get subsidized. That's when the FERC intervened in that process.

That is an inevitable response if you don't have something that's more compatible with markets and the incentives. Some pricing, incentives, and decision rules are not compatible with broader definitions of efficiency. There is legitimate concern that other options ought to get subsidies too. It's hard to draw that line in the U.S.

QUESTION: You asserted that FTRs were a necessary condition, and I want to consider the additional necessary conditions. Is it possible to dish out more property rights than just FTRs, or to strengthen FTR property rights to prevent free riders. For instance, an FTR could exercise minimum usage charges to prevent free riders. Are there additional structures we can add to prevent free riders?

ANSWER: In principle, if it allows more transactions, you can identify them, and they create FTRs.

QUESTION: What if they completely relieve the constraint?

ANSWER: Well, then you'd get into the issue that there is a lumpiness problem, and is it materially changing that ex post? If so, then it falls into the lumpy category, and a public contest for investment would be initiated. My understanding is that de minimus investments are unilaterally decided by the company, subject to the regulator approving them. Other investments are also made by the existing transmission incumbent. The cases where they're not is when another entity can do it cheaper and better. At that point the argument that the incumbent should do it is hard to sustain. This isn't a rejection of the independent transmission company model. An ITC is an integral part of the story. There are other issues that we could develop as well, like essentially pricing the transmission capacity.

ANSWER: Looking at the fourth line in Argentina, the constraint on the existing transmission was stability oriented. One solution was stabilizers located elsewhere in the system. These reliability issues were expressed in the form of interface limits that affected prices. So while these were reliability issues, they were also economic issues.

QUESTION: Was there any discussion about the effect on losses? You build a new line, and other lines are less loaded, and you get fewer losses.

ANSWER: That was part of the economics. They had marginal losses in LMP. If you're modeling properly, all of that's going to be recognized.

ANSWER: I hesitate to say anything about FTRs but the pressure for them in Argentina came because it was perceived that the system had failed to build an obviously economic piece of transmission. The question was how to incentivize people to build more transmission. Generators were worried that competitors would come along and push them off. They wanted transmission rights to stop others from getting future access to the line. That was one of the main motivations leading to NERA, and government consideration of financial transmission rights.

There were lots of different proposals and one was eventually implemented. This varied, but never got implemented permanently. All the investment has been without these FTRs. I don't know whether they're necessary. If you're introducing this approach in a system that already has FTRs, then you've got to integrate it in some way. Whether it's actually necessary is unclear.

QUESTION: The "beneficiary paying" is a simple pristine concept but everybody has a different view of what it means. Here's one view. If you were the person that requested the transmission service that tipped the balance that beat the house that Jack built, and you needed a new facility built, you paid the full cost of that facility because you were there at the time; I call this the "tag, you're it" theory of transmission construction.

Others point to the Argentine experience. This is a hybrid, where affected customers vote in some kind of panel. One concern is that when users pay for it, does that change over time, so if you join or leave the system, that changes? That's a different idea of beneficiary. I don't want to use the word socialization because there's an argument that everyone on the grid benefits.

If we have these gradations of beneficiary pays, from full socialization because we all benefit, to the last one who walked in the door that tipped the scale is the beneficiary. Let's define who is the beneficiary, and how you determine this.

ANSWER: Current proposals in my region argue that one entity requests an upgrade to be built. Without their service request, you would not have built it. Even if someone else has flows over that facility, if they didn't require it or need it, then they are not a beneficiary. So our current definition is the "tag, you're it," version.

ANSWER: These definitions are derived from different entities. "Tag, you're it" is the integrated utility version. It's the "I didn't need this; I don't want it; I didn't ask for it; you're going to pay for it." In a market with LMP, you can put a transmission line in and there are winners and losers . You can't see that in an integrated system that doesn't use LMP. They take on different meanings. If you're going to use participant funding, you need LMP so price signals will react properly. Otherwise, it's difficult to find beneficiaries and losers.

QUESTION: PJM has a "but/for" standard for participant funding on anything that's not needed for reliability. At the Transmission Investment Conference on April 22, they were publicly questioning whether that system causes enough signals to be sent to get enough money to build a robust system, and wondering about alternatives. Could you please comment?

ANSWER: This concerns cost recovery. There's not enough money to recover the cost from the price differences on the ends of the line. LMP is necessary but not sufficient to get this done.

ANSWER: The Argentineans asked, "What is benefit?" Who knows? This is a philosophical question. If we allow economists to get to work on this, we'll never get an answer, or we'll get a different answer for every economist. If we leave this as an open issue every time an investment is proposed, it will never get settled. We must legally specify a method for defining benefits. For instance, use the system operator's load-scheduling system to define what would happen if an investment came on and someone had an increase in load. If there were a demand load or an increase in generation, would there be an extra flow on this line from the change? By specifying it as an engineer would, it ends debates about who the beneficiaries are. Further, it could be changed if necessary. It doesn't matter what the specific allocation and definition of beneficiaries are as long as they're well-defined and objective, and not the subject of continual dispute.

ANSWER: I agree with the "but/for" standard. I disagree with the Argentines assertion that you can't do the calculation. You can't do cost-benefit analysis without making admittedly uncertain judgments about cost and impacts. It's uncertain, but you have to do that in order to decide whether to go ahead. It's a process which produces a range of confidence about the cost benefit. It's not just the load flow. There are important differences between mesh and radial systems. You need to examine the economic impacts and then you can identify those beneficiaries. They are identified ex ante, location specific. They can't be changed all the time because it creates perverse incentives for uneconomic investments that shift costs to others. It's called the "behind the meter" problem in New Zealand, where people try to build generators behind the meter to avoid paying the transmission charges.

There are two kinds of problems to consider. One is "tag, you're it," and it doesn't have a major impact. One should be paying for it, and getting the benefits that you pay for. The other is that you only need a bit, but they have to build a lot. That's the lumpiness problem. This requires the public contest method, where you identify beneficiaries and allocate the cost, after a voting process or some other decision rule. You don't just say you have to pay for the whole thing, and you don't get the benefits, but rather do it ex ante to properly identify the beneficiaries.

QUESTION: So you would put a public contest on it if it were lumpy?

ANSWER: Yes. In Argentina, it might be just an alternative rule, or I would tend to put the two of them together.

COMMENT: Make sure you distinguish between "big" versus "excess," because you can have systems with extra capacity that are not lumpy, and are not failures.

ANSWER: I tried to make the distinction carefully. Argentina called them big; that was their definition. I used "lumpy," because it has a material effect on market prices.

QUESTION: You've proposed a bright-line test here to distinguish, or support, regulated investment. I'm having difficulty with this market failure justification test. If a project is large and lumpy enough to materially affect market prices, it makes the after-the-fact rights worth less than the cost of the investment. That sounds so judgmental that I can't see how a planner, faced with applying that test, wouldn't end up doing what the central planner wants, which is the test you're rejecting. What's the difference?

ANSWER: It's not so judgmental or trivial because it's hard to structure the numbers and analysis in such a way that it's economically beneficial, and you can't make money doing it. You can tweak the numbers with "judgments" so that the FTRs don't turn out to be worth much afterwards. However, this is usually not economic, in most cases. Similarly, if it's beneficial economically, it's almost always going to turn out to be something you can make money on. It's actually a narrow band of projects that are a tough call. It's not perfect. However, it avoids many things that you don't want to do.

Also, it provides an answer to the question of the "everything else" projects. Most competing investments are not lumpy in the same way. They don't pass the test. It's a principled answer to why you don't subsidize everything else at the same time. The calculations are not pristine and easy, but the evidence from Argentina shows many investments where you didn't even get property rights; you didn't get anything but what happened by chance, and people were making all of these investments. No one noticed because it wasn't controversial. What we need to address is the narrow band where people are compelled to pay, and it's not such a hard test to implement.

COMMENT: My perspective comes from involvement in independent transmission projects. Investment in independent transmission has been handicapped in the last 3-4 years by the same things that handicapped investment in generation. Investors in electricity have been run away by problems in the generation market. As confidence recovers, some of the money will come back to transmission as well.

Second, financing a transmission line with only FTRs is like trying to finance a generator with only energy revenues. Our markets separate energy payments and capacity payments. It's naïve to finance a transmission line solely with FTRs, without regard for their capacity impact, or the need for a capacity payment.

Third, we should evaluate transmission opportunities on a combined energy and capacity basis. A good example is the Neptune line between New Jersey and Long Island. Long Island's energy price is about $20 per megawatt hour higher than New York. That might finance a transmission line by itself because it's so large. But if the line happens, then it will have an impact on the energy spread. You must also rely on the second spread, the capacity spread. It takes roughly $1,500 a kilowatt to build a power plant in Long Island, and $600–700 a kilowatt in New Jersey. New York has a locational capacity market. Thus, the load-serving entity in New York faces high capacity fees this means that LIPA (Long Island Power Authority) can buy a transmission line with access to cheaper capacity in New Jersey. This is economic as long as the combined cost of the line and the New Jersey generation is cheaper than generation on Long Island. If it costs $1,500 a kilowatt to build Long Island generation, and $600 a kilowatt for generation in New Jersey, any transmission line under $900 a kilowatt is economic. This has been done; it got funded, got a contract, and is getting financed. Construction begins on July 1.

COMMENT: The last speaker's notion of what's unhedgeable is exactly right. It's an oxymoron. If something is unhedgeable in terms of congestion, you would not be getting power. Unhedgeable is a euphemism for when people don't like the cost of the hedge.

Second, stakeholder processes that addressed the lumpiness issue or socialization of costs were really a debate about cost shifting and demonstrated that beneficiary definitions were unclear. The more clearly one defined the beneficiaries of relief from congestion, the less happy the people who promoted the economic program became.

Third, one speaker argued that once an economic program was put in, cost-beneficial projects came out of the woodwork. That's not exactly true. The lists of projects are only screens. They're rough estimates of cost benefit based on the questionable notion of unhedgeability to begin with. Only some are truly beneficial in terms of the rights themselves. Once the screens have been passed and the specific projects are evaluated in greater detail it gets more difficult. Even using this definition of unhedgeable congestion, and incorporating requirements for baseline reliability, only one project has been identified as economic enough and reasonable to pursue.

Empirically, it was a questionable initiative to begin with. There was no great failure that needed to be addressed. A number of the other systems in the market, including some of the capacity designs and capacity-related property rights, were sufficient.

QUESTION: In the early days of the PJM LMP system during the 1990s, the Delaware area was a load pocket and would soon have congestion and higher costs. There were proposals to build big 230 KV lines along an environmentally sensitive area in that territory. It was easy to see where the congestion was from the prices. Projects were proposed to build the new 230 line there. However, through the PJM transmission process, a number of 69 KV and small transformers were upgraded, and congestion has disappeared. It was severe in 1998 and 1999. Once they did the upgrades, this multi-million dollar transmission project wasn't needed or put into rate base. This is an example of how LMP is a necessary, but not a sufficient condition.

One of the concerns for merchant transmission as a business is the concern for other projects that are really big. If a little merchant upgrade is put in for more transmission, say into Wisconsin, to get FTRs for it, or some long-term contracts to do it. This incentive is made risky because there's PR that we have a third-world transmission system, and that lots of transmission for reliability is needed. This would eliminate the benefit of the small upgrade. It's more pernicious than generation and the environment for investment in energy. The regulated transmission creates a barrier to merchant transmission because you know it's there. It's the 800-pound gorilla. It limits the ability to focus on merchant investments because you don't know what the regulated environment will call for.

COMMENT: Participant funding in PJM is misunderstood. Where it is, why it is, and what it is. Without going through all that, roughly two-thirds of the transmission projects in PJM are participant-funded, primarily by generators looking to interconnect or build associated network upgrades to get capacity deliverability rights. These rights are another product they can sell in PJM. Whether the capacity market should exist forever is a different issue. Hopefully there will be enough robust demand-side response that ICAP, capacity markets, and price caps can disappear one day. Economic transmission upgrades in PJM were forced on them FERC order.

Certainly people continue to argue that we have an under-built transmission system, and a lot of transmission is needed to make a robust grid and eliminate congestion. However, you can end up doing those things when it is not the economic thing to do, as they did with the fourth line in Argentina. In "economic" projects, the congestion money you save won't pay for the upgrade. Many projects could reduce congestion, but they don't meet the hurdle that they've built into the test. The predominant upgrades that occur are incremental, not lumpy. The way a transmission line is built includes a circuit breaker somewhere on each end, a disconnect switch, a wave trap, conductors, and various sag limitations, etc. These things aren't rated at the same capacity because they come in lumpy engineering numbers; that was done some time ago on most transmission. Operators can upgrade a limiting piece and get the entire circuit upgraded beneficially.

These proposals don't address siting issues, and other risks a transmission owner faces. That's why they ought to be incented. However, I don't agree that there's that much risk. You can build out the grid in an incremental fashion and it can be much more robust. It doesn't have to be expensive, if you do it smartly.

ANSWER: I agree. There's no "fourth line" on our system. My company has been building facilities, almost two billion dollars worth in the last five or so years. We've had TLRs over the years, and when they're concentrated on one flow gate, they are fixed. We have installed every large facility that needs to be installed or that would be economic. Our grid is far beyond a third world grid, there's plenty of new technology in the system.

ANSWER: I agree, too. A competitive process can bring out lower-cost options. I described some stabilizer and series capacitor projects done in Argentina. The big information function new to the transmission business that historically is the consideration of what things can be done and their impact. The business will be structured differently; companies will be finding the beneficiaries and selling those things to them, being the consultant. In a competitive system, you get people crawling everywhere trying to find beneficiaries, to make a project go because there is a mechanism that makes the project work for the constructor.

QUESTION: I'm concerned about items that are not incremental investment in the ordinary course of business. I have just participated in fifteen months of proceedings that approved 75 miles of transmission line through beautiful land in the northeastern United States. The concern was not about under-investment in transmission, but over-investment in their backyards. Why subsidize this, and not everything else? Although it's appropriate to start with funding -- sources; cost-justification; returns; -- that's too limited, other things come in, too. It's not possible to deal with funding and the other things separately. These are not sequential problems, they are interlinked.

In siting, there are two issues that are intertwined. One is environmental permitting, where the standard is undue adverse environmental effect. The other is condemnation, where the standard is public necessity. Courts and utility commissions require serious consideration of alternatives for both issues; often an even-handed consideration of alternatives. The models discussed earlier include mandatory pooled funding whether it's the losers in the vote for a consensus, or a mandatory pool or a socialized pool. If money is being collected involuntarily for transmission and not other solutions, then there are legitimate concerns about whether the transmission will meet the environmental impact or necessity tests. Those who focus on the money will be creating a trap if they get started in a way that corrodes legitimate consideration of alternatives. The last speaker tried to create a line that would allow pooling for lumpy transmission, but not anything else, like efficiency or distributed generation. However, I'm not sure the line survives, because other alternatives have lumps in them, too. Do tests for environmental impact or takings get corroded by pooled funding investment processes?

ANSWER: While I'm not an environmental law expert, the point you're making is compelling because when you're considering environmental or siting approval, you should consider the other solutions. The analysis might show that energy efficiency would be better, have less environmental impact, and be cheaper than a line. Presumably the permit is not granted to the line, and is granted if somebody wants to do energy efficiency. This is separate from the question of using pool funding to pay for one, both, or neither of them. If a line is not as cost-effective as energy efficiency, and it won't happen if we don't pool the funding for the transmission line, then you don't want to do it. This is the case even if energy efficiency isn't worth doing because of the other problems associated with it. It's a market test which says you shouldn't be building the line.

It's not a given that a line needs to be built, and energy efficiency investments are not generally lumpy. They come in relatively small bites. If it's economic to do it, and pricing is correct, then people can do it and make money in the marketplace.

You can make that decision in the environmental context appropriate, but it doesn't mean that because somebody else is going to get a subsidy, you should get one, too. That's a separate test. It might mean that neither one should get it.

COMMENT: How do you look at the system as a whole? Participants will look at the implications for themselves. The main Argentine grid is very radial, and what happens in one place doesn't much affect other places. However, the sub-transmission grids are more meshed and integrated. Buenos Aires province, an area the size of France, has about 5,000 kilometers of mainly 1-3-2 KV line. The beneficiaries there are three large distribution companies and over a hundred municipality-run systems.

The way they handle it is that they have formed an association. They've drawn up a ten-year plan, and a budget. They've each put in money, and decided on a rational scheme of investments for the province as a whole. They've talked to the transmission company, as well. Broadly speaking, that's gone very well. There have one or two occasions where they've differed. There, the beneficiaries have simply said we don't need it. We've got a more economic, suitable solution that we prefer.

COMMENT: I want to clarify information about congestion on the Del Marva Peninsula. The congestion was primarily caused by planned upgrades to the system being installed during that time. The FERC findings showed that parties impacted by congestion had alternatives to hedge the congestion. Their costs could have been prevented; the improvements were not of the wave trap variety; they were the big lumpy things. They were already in the PJM R-tap, they were in existing rights of way. In fact, one party exposed to the congestion looked at their costs, and chose to pay an advance on one of the already planned improvements. The did this to offset their congestion and take the financial rights. The system worked the way it was supposed to. The peninsula is, by its definition, a radial system, and these big lumpy things will occur. LMP sends the signals to do the right thing.

Session Three. Renewable Portfolio Standards: What Works.

Nineteen states – including, recently, New York, Pennsylvania, and Colorado -- have adopted some form of portfolio standard that requires a specified percentage of electricity delivered in-state to come from renewable sources by a given date. The U.S. Senate approved a national RPS goal (10 percent by 2020) as part of broader energy legislation in the 107th and 108th Congresses, and similar legislation has been reintroduced in the House and Senate. The record to date, many contend, indicates that some RPS' are stimulating renewable energy development at reasonable costs more effectively than others. What are the key features of successful RPS', and can their models be replicated in other states that are just now considering or implementing similar requirements? Has the experience been notably different in restructured and non-restructured states? Where there is retail access, how is the RPS enforced and against whom (e.g., POLR providers, customers who exercise choice)? How essential are credit-trading and certificate-tracking systems for meeting RPS targets? What are the prospects for modifying existing standards to reflect lessons learned in other states? If a national RPS gains momentum, what should its core features be? What effect, if any, has the implementation of RPS had on prices to consumers? What effect, if any, has RPS had on prices on energy delivered from non-renewable sources? Have particular types of renewable technologies benefited more than others? If so, why has that occurred?

Speaker One

Texas has a fairly aggressive renewable portfolio program. It is predominantly wind, mostly in West Texas and up in the Panhandle. For centuries, wind was the enemy of farmers and ranchers in this area. It is producing revenue for them now, and allowing them to hold onto large sections of property that were uneconomic. That is one facet of the argument in what has become a fairly active debate.

The Texas renewable energy program came with the movement to a competitive market. The comprehensive legislation known as SB-7, Senate Bill Seven, passed in 1999, and became effective in 2001. The present goal is 2,000 megawatts of renewable by 2009, primarily wind, with a small amount of solar and biomass. There is a program for trading renewable credits; several firms are active in this market. Our definition of qualifying resources is broad, but it's mostly wind.

Here's the way it works. Generators produce the RECs; the reps buy them, and then over time, retire them. There's a mathematical formula based on the quantity of load each REC uses that determines how much they need to retire. There are also voluntary retirements. Most of that comes from our coops and munis.

There was extensive discussion yesterday about transmission policy. This is important because most of the wind is in West Texas. It's five or six hundred miles from load, and there isn't any native load where the wind is. This power is going primarily to the Dallas/Fort Worth area, and some of it to San Antonio. We use a postage stamp rate, which means that it doesn't matter where you're located on the grid. Distance is not a factor, and there is a standard interconnection agreement. Upgrades are rolled into regional rates. For example, a project in the TXU region near the Dallas/Fort Worth area, would be reflected in the cost of service throughout ERCOT.

The ERCOT stakeholder process, which includes representatives of all sectors, considers proposed transmission enhancements. those must clear their way through the process to come to the Commission. Through 2004, we had installed almost 1,200 megawatts of new capacity, mostly wind. It'll be close to 2,000 by the end of this year. The RECs that were retired in association with that, were about 2.7 million, and in addition to voluntary. There are about a thousand windmills in the Panhandle and West Texas. The new ones are usually a megawatt and a half. We have one three-megawatt experimental turbine that is like standing next to an aircraft carrier. The size of it is absolutely staggering.

Many of the issues concerning residential customer impact involve money, who pays for RECs, and how much. Generally one has to acquire about one REC for every hundred megawatt hours that is sold. If a customer's monthly consumption is one megawatt hour, then the rep buys .01 REC. That equals about 15 cents a month for the customer. Public opinion polls among residential consumers are overwhelmingly in favor of wind. Some polls have indicated that people would be willing to pay as much as 2-5 dollars a month for additional wind. Clearly, that's easy to say before you get the bill, but it gives us an indication of the public support for wind.

Competitive producers decide where to build and they build where the wind is. Projects located close to the source obviously have a competitive advantage. We've seen large clusters of windmill projects. There are several mountains in West Texas that have hundreds of windmills in an array all linked together. There isn't much solar at all but we hope for increases soon.

One of the effects, via deregulation and retail open access, is that almost all reps -- retail electric providers -- have a renewable offering. Some have more than one. Some, such as Green Mountain or other renewable only providers, have a higher price than the historically vertically integrated retail electric provider, and they're still able to sell that power. Austin, our most environmentally friendly large city, has an overwhelming demand for renewable products.

Now, transmission is a big issue and the issues at the Commission is always about price. This is because our transmission costs are uplifted to everyone, and load is responsible for picking up their pro rata share. Not surprisingly, there are large industrial users with strong opinions about wind. There is a continuing debate about the costs of transporting wind. The 2,000 megawatts presently supplied has required about a billion dollars of transmission enhancement. Upcoming legislation that's probably going to pass will get this amount to 5,000. So the total will be 6,000 or 7,000 MW. That requires one to three billion dollars in additional transmission enhancements.

An earlier proposal to get us to 10 percent by 2019 would have required seven billion dollars of transmission enhancement.

Further, we are learning a lot about wind. ERCOT and its engineers are continuing to learn to manipulate and understand wind and its effect on the grid. There are certainly voltage support issues. It is not dispatchable. It is off peak. The West Texas wind blows mainly in the mornings, and in the evenings in the wintertime. However, our peaks in Houston are on a hot August afternoon at two o'clock. These are significant issues. But the system is learning how to work with it slowly. We've encouraged the legislature to proceed judiciously when they want to add more renewable targets because we don't know enough about handling 10,000 megawatts of wind right now. Think about it in this context: Let's say it's a pleasant March afternoon. Our load is about 30,000 and if we had 7,000 or 8,000 megawatts of wind on the grid, no one knows how we manipulate that. It's a quarter of the load.

The current legislative proposal of 5,000, which seemed like a lot of wind some time ago, is the most conservative proposal. That one has the leadership. Though, interestingly enough, the bill (Senate Bill 533) was referred back to committee last night. Someone who doesn't want more wind has some smart lawyers looking at this. There are only about ten days left in the session. It'll be interesting to see how this resolves. Another proposal was 10,000 megawatts by 2015. The most aggressive one is 10 percent by 2019.

An interesting proposal is the creation of renewable generation zones. The idea is to cluster the generation of wind in zones to centralize the transmission that goes out there, rather than allowing generators to put windmills anywhere and then us connecting with them. If we can create cluster incentives, then it may centralize the lines. For example, one proposal is considering a 765 KV line from West Texas, which has about 765 people, to the Dallas/Fort Worth area.

A good source for rules and regulations regarding renewable is PowertoChoose.org, or PowertoChoose.com. This shows renewable offerings for retail choice by the input of an area code. If you're not in a muni or a coop area, you usually have between 10 to 14 retail offerings.

Speaker Two

I will talk about the experience in California. The state has both investor-owned and municipal utilities. And it's split about 80 percent on the demand side with the investor-owned utilities; about 20 percent with munis. There are three large IOUs: Pacific Gas & Electric; Southern California Edison; and San Diego Gas and Electric. On the muni side, there's Los Angeles Department of Water and Power, Sacramento, and a host of smaller utilities. There are also energy service providers; they are load-serving entities that serve the retail competition, or direct access side. And they currently serve about 13 percent of demand in the investor-owned utility territory. The state is under a statutory suspension of direct access, so this number can diminish, but it can't grow right now. There are also community choice aggregation programs, which are a hybrid of retail choice. They allow a local city to aggregate residential and business load, and then purchase power on their behalf. Customers can opt out and stay on utility service. The program is allowed under statute, but the PUC is still formulating all of the rules. There's virtually no participation, but it's possible that this will increase over time. The different categories are important, because the RPS is applied differently to each of them.

Historically, California has decreased from its peak renewables use. During the deregulating process there was a drop in renewables under contract and on line. There are two energy agencies. The California Energy Commission does the siting of power plants; implements energy efficiency standards; and also handles the R&D side for energy. The Public Utilities Commission does the traditional rate making and oversees power procurement and certification for transmission lines and power plants.

The Energy Commission tried to put in place an intricate subsidy program on renewables to foster their development in the 1990s. It never gained traction. Instead, we have adopted the renewable portfolio standard. Our RPS is embedded in statute that requires 20 percent by 2017. The energy agencies in California have said that we will accelerate that goal to 2010 as a policy goal. There may be a bill in our legislature now that would mandate it by 2010. We've got about 45,000 megawatts so this is a big chunk, possibly up to about 9,000 MW.

Traditionally we've had separate requirements for the investor-owned versus the municipal utilities. The municipal utilities can basically set their own standards and they are lagging in terms of bringing renewables on line. The Public Utilities Commission is in charge of enforcing RPS standards for the IOUs, and the ESPs -- who are serving the direct access load, and our community choice aggregators. The PUC process includes standardized long-term contracts; a bid ranking process, and a complex approach called "best fit, least cost." Since the goals are set annually, if a utility has excess in a year, it can bank it and use it against a deficit in the future. There is also a program using the public goods charge. It goes on the distribution rates that the Energy Commission Agency implements and pays the above-market costs for renewables. The PUC has a long way to go. It's an area of concern at both the PUC and the Energy Commission because there's so much to do over the next five years in order to satisfy the long term goals.

Each IOU submits plans to the Public Utilities Commission. These show what the utility sees as its needs in order to meet that year's goals. The PUC approves it, after public comment, and then the utilities go forward with an RFO which is open to all eligible bidders. There are not specific targets for any particular renewable technology. All renewals can compete. They can also bid in as many solicitations as they want; a generator with a renewable project can bid to more than one utility. Once they are short-listed they have to commit to one utility. Each utility develops a market prices referent after the short list is set. It is based on the fossil-fired market price. The Energy Commission has funds available to pay the increment above the market referent. Finally, there is competition between the short-listed generators to see if they can bring costs down, so that the subsidy is as low as possible. Once the commission funds are awarded, the utilities sign contracts with renewable generators, and those are sent to the PUC for approval. This solicitation only occurs with renewables, and the plan is to do it annually.

The biggest challenge is with transmission and extensive wind growth. As we've heard, it's not located where the load is. To attain the renewables the state wants, we need new transmission. Our problem is how to get new transmission built so that it is available before the generators have necessarily got contracts for their project. This is our chicken-and-egg problem. We can't direct our utilities to fund transmission expansion, unless we know there are winning projects there to justify the transmission expansion. Can the projects can really go forward? The utilities are not willing to say what the price is without knowing what the transmission cost would be.

Southern California Edison Company and our PUC have filed a transmission proposal to the FERC in their service territory. It asks FERC to approve the funding using new rules that are restricted to renewable development. It would create new trunk line capacity, and grant rolled-in rate making, but all in the context of developing prospective renewable projects. The study group for this effort includes Southern California Edison, the potential generators, the ISO, and the Energy Commission. There has been extensive work to identify technical and economic potential that exists for renewables but all of the projects aren't specifically identified and committed to by generators who would be served. There's no dispute about the capacity to bring renewables on line but it's clear that there aren't yet specific projects lined up that would be served.

Edison is asking – with the PUC and the Energy Commission supporting them – for permission to have rolled-in rate-making. Furthermore, they want to change FERC's policy on abandoned plant if the hoped-for renewable generation doesn't materialize. There's a small likelihood of this happening, but the utility is asking for that relief to be prudent. It is a very proactive approach toward renewable planning. It requires solid planning and thinking about what the renewable potential is to prevent spending millions in ratepayer money on the hope that you've got this stuff out there.

Further, the state requires long-term procurement plans that look out ten years every two years from the investor-owned utilities. The first round of those were approved in December. The utilities are explicitly required to favor renewable resources in any of their all-source solicitations. Another way the state favors renewables is via a carbon adder used in the evaluation of the all-source bid process. Currently they're using eight dollars per ton of avoided CO2. This is used in evaluating bids, but no money is paid out. The utilities are starting to institute that process as of December, and there are procurements going on this year.

California does not currently use RECs. In a pending action, the Commission is deciding whether they are able to institute RECs without legislation. We will probably end up with some sort of additional legislation before we proceed. The Commission is also supposed to be instituting the renewable portfolio standard against the ESPs, who are serving our direct access load. The PUC is paying considerable attention to it because it's financially significant. The rules are still in development and there is some tension because the ESPs are concerned about being under the jurisdiction of the PUC. They understand the political necessity of becoming part of the RPS standard. I expect they will be included in our program by early 2006.

Speaker Three

In the past, there were no estate RPS' other than a couple of legacy mandates in some regulated states. The larger question then was whether RPS' were politically feasible. The good news is that we now have RPS' in twenty jurisdictions in the United States -- nineteen states, plus Washington, D.C. If they succeed, they will account for almost 26,000 megawatts of new renewable development by 2017; significant carbon reductions, the equivalent of almost ten million cars off the road, or planting three billion trees. California is responsible for a significant proportion of that result.

There are RPS' in both red and blue states. They're exceedingly popular. I've seen extensive polling nationally and state by state, and two-thirds to three-quarters of the population supports them. The results are consistent even with a dollar figure per monthly bill, or a percentage of the monthly bill that exceeds normal cost projections for the area. Further, several states are considering enacting new RPS' or increasing existing RPS'. Over the next five years, we could see an additional 25,000 to 30,000, maybe even 40,000, megawatts from new and higher state RPS', on top of the current 25,000 megawatts of commitments. This is in addition to about 15,000 megawatts from non-hydro renewables before RPS' really started taking off in 1997–1998.

An increasing number of independent analysts have concluded RPS' are now the primary driver of new renewable development in the United States. The federal production tax credit is a critical component of that, particularly in the short term. Over the long term, renewables should become increasingly cost effective even without the production tax credit.

About three-quarters of the wind developed in the last five years is in RPS states. The range of renewable development that's attributed directly to RPS' ranges from 50-75 percent. Like Texas, most renewable development to meet RPS' has been in wind power. The same is true in voluntary renewable markets and in green pricing programs around the country. In competitive marketing programs, the supply percentage is over 90 percent from wind. Wind is the most cost-effective new renewable source at the moment.

The purpose of the RPS was to help drive the most cost-effective energy renewables into the marketplace so they could begin to achieve economies of scale, reduce prices, capture environmental benefits, and diversify our fuel sources. It seems to be working. Now, it's not working everywhere; it's too early to tell in many places. Many RPS' have only been enacted fairly recently and we don't have significance experience with them. There have been some significant successes to date, however. EIA has concluded that at least 2,300 megawatts of new renewables already in the ground today are directly attributable to RPS'. In both Texas and California, contracts are being signed for renewables.

Minnesota and Iowa had some of the earliest requirements for regulated utilities. Minnesota has increased it twice since the first requirement. Currently, they are considering broadening the requirement, which now applies only to about half of the state's load, to areas under voluntary target regimes. In Iowa, it's already exceeded its target. In Wisconsin, the first non-restructuring but new-era RPS to pass has enough renewables under contract to meet requirements through 2011, and they are considering increases from 2 percent to 10 percent. In New Mexico, RPS is already contributing to renewables in the ground. It's not all good news, of course. Like any new policy, there is a lot to be worked out. RPS' have proven to be more complicated than anticipated. There are still implementation problems to be resolved.

Massachusetts is not the only problem. Siting and permitting are problems in the Northeast as well. Surveys have shown that developer's inability to secure long-term contracts stalled a number of projects. As a result, we have companies in Massachusetts paying $50 per megawatt hour in alternative compliance payments, rather than signing long-term contracts for RECs that we know are available for about $25 per megawatt hour. We are seeing a lot of problems with long-term contracts. They are essential for financing new facilities, especially capital-intensive projects like wind.

Nevada also has contract problems oriented around credit problems with the utilities. In Maine, their original RPS is almost 50 percent renewables. Their original purpose was to preserve at least 30 percent of their supply from renewables in restructuring, rather than to create new renewables. Arizona has issues with under-compliance. In California, the initial bid pools are smaller and more expensive than many had expected. There are questions concerning deliverability and transmission. Their RPS emerged from legislative sausage-making and has made it difficult to go forward efficiently. In New England and the Northeast states, there are public acceptance and siting concerns with wind, and biomass to some extent. Constrained supply leads to high prices. Transmission concerns are a big issue in several states.

One trend in a number of states is that cost caps put on RPS' are so low that they result in little or no renewable development. Companies simply pay the alternative compliance payments. Most states with alternative compliance payments mandate that the funds be used to secure renewables. Massachusetts has been auctioning alternative compliance payments as long-term contracts. This will eventually ensure RPS standards, but it defers the benefits of getting the renewable in the ground. It is a prospective backup mechanism, but it should not be a primary compliance mechanism.

Long-term contracts and standards are also problematic. A number of states have utilities, providers of last resort, who are unwilling to sign long-term contracts. Alternately, the suppliers are not creditworthy, or are uncertain of how the market will evolve, and will not enter long-term contracts. There is a chicken-and-egg problem that needs to get unstuck.

Broad applicability, and carefully balanced supply and demand, are vital to successful renewable standards. It is possible to shoot too high too fast. The standards should have sufficient duration and stability with well-defined and stable resource eligibility rules. If eligibility is variable, sources that are currently eligible don't know if they will be in the future. In Massachusetts, discussion about changing the biomass eligibility standards has caused a real chill in the market for wind. Finally, sufficient and credible enforcement, stability of rules, and clear treatment of out-of-state resources are also necessary.

There is a lot of momentum. Six new states plus Washington, D.C. since last year's wind conference in Denver. Many states are accelerating, or enacting higher standards. Every standard is different, sometimes drastically, in design. Certainly, some are working better than others.

One encouraging trend is the use of a set-aside or credit multiplier for solar and distributed generation. This is to encourage more diversity among renewables. This will bring diversification and additional benefits, but also increase the short term costs. Other areas of improvement include significant design compromises in some of the more recent RPS'. The big problems are the long-term contracts; siting and public acceptance; and committed regulatory enforcement – particularly with so many new RPS'.

Finally, the federal RPS debate is current, as a debate on federal energy legislation kicks off in the Senate Energy Committee. Senator Bingaman's RPS was included in the Chairman's markup going to the Energy Committee. However, Senator Alexander from Tennessee got it pulled. He has a vacation home in the mountains, and doesn't want wind development on the ridges near him. Understandable -- nobody wants energy facilities of any kind in their backyards -- but unfortunate. There will be an amendment offered from the floor and we expect success again in the Senate. The RPS passed in 2002, with 58 votes, including 10 from Republicans. However, the House will probably not accede in conference. Two days ago, Representative Barton said, "There will be no RPS and no carbon reductions in this energy bill."

Congress is also discussing the inclusion of other resources within the RPS such as energy efficiency, combined heat and power, and, in the Senate, advanced coal through IGCC, with or without carbon capture and storage. Even advanced nuclear is being considered. It's premature to look at these other resources. There are not workable models of expanded standards in the states, though Pennsylvania may provide a standard for some of those resources in a second tier.

Every state has different reasons for implementing RPS'. The political drivers vary a lot. Renewable energy sources are the only class of sources that provide a complete package of benefits that include fuel supply diversification and competition for fossil and nuclear sources. In the short run, the RPS reduces demand, and prices, for fossil fuel. In the long run, it creates new competitors, new options, and new choices. Other benefits include improved energy security from diversity and domestic development; reduction in the entire environmental impact from fossil and nuclear fuel cycles from mining and drilling, to fuel transport, to waste disposal; avoiding water use; avoiding fuel depletion; and any risks we face from passing the peak of energy resources.

On the federal level, the PURPA era resulted in a stall in renewable generation, a decline that occurred during the debate over restructuring, and uncertainty in electricity markets. New projections from EIA based on current state RPS' and alternately, projections of the Senate's 10-percent-renewable standard, exceed the most optimistic development for continued RPS' in the states. A federal RPS is critically important. The EIA's National Energy Modeling System [NEMS] demonstrates that even a 20 percent RPS using current gas price projections would reduce electricity and natural gas bills nationally -- about $50 billion cumulative net present value savings to electricity and gas customers. This is due to the simple supply/demand issue with fossil fuels, particularly natural gas. You reduce demand; you take the pressure off natural gas; and reduce its prices for electricity generators, for industrial consumers, for farmers, for people that heat with gas, as well as for electricity.

The EIA NEMS provides pessimistic projections for wind. There is no reduction in price forecast for wind over the next twenty years. I don't know any renewable energy analyst, in the national labs or anywhere else, who is that pessimistic. However, even using these assumptions, they find net present value savings from the RPS under current fuel price projections. Votes in 2002 for the federal RPS showed broad geographical support, particularly in the Northeast, the Midwest, over into the plains and the far west, as well as Florida and Louisiana. There has been a change in composition in the Senate since then, obviously. There are important new champions for RPS' in Senator Salazar from Colorado, and Senator Obama from Illinois, replacing some moderates and Democrats who weren't supportive. It's only a matter of time before the economic development benefits of renewables, and the environmental carbon reduction mean that we will have a federal RPS.

Speaker Four

What is the RPS for? Is it the best, or even a tolerably good way of accomplishing its goal? In raising these questions, I'm assuming the purpose of the RPS is to deal with environmental and other consequences of power generation that are not properly accounted for in the market-based decisions of electricity consumers and power generators. In particular, environmental policy, but generally to address what economists call externalities; specific consequences of power generation that the market doesn't address. Other categories of externality are worth considering, and whether the RPS is able to tackle them.

Economics has developed a fairly clear view of the principles for designing environmental policies. First is to deal with each externality or type of pollution explicitly. Control outputs; that is, control the emissions themselves that are causing the harm. Don't try to control the input to the processes. There is a long history of mistakes in environmental policy that have come from violating this principle. Second, equate the marginal cost of control of this specific emission that you're worried about across all of the sources that produce those emissions. This is a basic principle for achieving an environmental quality goal at minimum cost. Those are hard economic tests.

There are two others that are important. One test is to design a program to minimize administrative costs. Some programs that look ideal may be excessively costly, and compromises may be needed. Finally, the other test is to match the geographic scope of the regulation and the externality being addressed.

The RPS violates every one of these basic principles. It doesn't address any externality directly. It specifies a technology, renewables, as opposed to other ways of generating electricity or dealing with the specific externalities. It doesn't address emissions performance directly; it simply says renewables. It applies uniquely to one sector at this point, power generation. It has administratively complex trading rules. This complexity comes from a failure to keep one's eye on the ball of dealing with emissions. The geography is mismatched with the problems that the RPS is trying to deal with. Some problems are local; some global. The RPS fits neatly in between, and not on top of the problems it's trying to solve.

What are the externalities that an RPS might claim to address? One is criteria pollutants, which affect urban air quality, human health, the national ambient air quality standard. So it's sulfur, NOx, mercury, particulates, regional haze problems. Greenhouse gas emissions and climate change are issues that the RPS is designed to deal with. Another argument for the RPS is to encourage technology development. This is meant to solve public goods problems in bringing new technologies into the market. There are others: energy security, resource depletion, other externalities associated with fossil fuels.

Performance on the criteria of pollutants is already required by law. There is a sulfur trading program; a NOx program; we're working on a NOx trading system; particulate matter and regional haze regulations are being put into place. Proposals for mercury regulations and mercury trading exist. The externalities associated with these criteria pollutants are being dealt with. Utilities are paying the cost for these other emissions, and they see that cost as they choose among different generating technologies. For example, mercury regulations will increase the cost of coal relative to the cost of other power generation. The RPS adds a technology requirement to the existing performance requirements.

Utilities already have incentives for addressing existing emission standards and caps efficiently. They have extensive programs for assessing future compliance for different kinds of generation, ranging from scrubbers on individual power plants for SIPS, to much broader regulatory requirements for mercury over the next twenty years. They plan generation and compliance strategy to minimize costs based on rules that are limiting, and in many cases, capping each of these emissions.

Second, the RPS will create zero improvement for any emission that's capped, like sulfur trading. If there is already a cap on sulfur emissions, an RPS still requires a renewables substitute for natural gas that will have no effect on sulfur emissions because there is no sulfur in natural gas. If there is a NOx cap, then using renewables to reduce natural gas or coal generation will free up the opportunity to produce more NOx somewhere else because it will create NOx credits. The cap is there. The RPS specifically requires a certain technology instead of having the market choose which technique will be used to stay within that cap. The renewable technology will simply fit within the cap and displace something else, while leaving the total emissions alone.

For criteria pollutants, the RPS will substitute for a less costly compliance measure, or lead to over-compliance if it's set so you have to give away NOx and SOx credits if you're going to sell a renewable energy credit. This over-compliance problem doesn't apply any cost-benefit test on whether an improvement is valuable or useful within the jurisdiction of the RPS.

Let's consider this history. The sulfur trading program included a sulfur cap, but also applied new source performance standards to individual utilities, and had a schedule for the installation of scrubbers. The new source performance standards generated a lot of permits and put sulfur emission credits into the market at a zero price. If you had to put a scrubber on your power plant, you had a set of credits because you had reduced emissions by installing a scrubber mandated by law. You would take any price for those credits because there was no incremental cost of generating them. For many years these excess credits created by the technology standards drove the price of sulfur credits below the marginal cost of reducing sulfur emissions. The technology standard not only required a particular kind of control, but also distorted the market price of the permits. The price of sulfur permits ten years ago were a couple of hundred dollars a ton less than they should have been. The excess supply of credits is reduced now and prices are around $800 a ton, which is a better indication of the actual cost of removing sulfur from power generation.

The RPS has the potential to do the same thing. For example, if greenhouse gas emissions have required emission reductions that will be in the market, the RPS will change supply and demand balance for emission credits. This has two effects. First, the existing technology standards in addition to the sulfur emission cap led to an apparent low cost of meeting the cap because the price of permits was low. However, the technology standard was actually replacing low-cost fuel switching with high-cost scrubbing, and driving up the cost of meeting the overall sulfur cap.

How can a renewable portfolio standard reduce the cost of power? Utilities already have ample incentives to figure out what their least-cost environmental strategies are. They bear the cost of current environmental regulations, and they perform under performance-based or competitive regulation that creates incentives to minimize the cost of generating electricity, and to achieve fuel diversity to minimize cost risks. The utility industry is making choices that minimize the cost of power.

Second, mandating technology rather than performance in environmental terms brings unintended consequences. The RPS has unplanned impacts like golden eagle mortality in wind farms. There are issues with biomass in terms of the emissions and, for climate change, whether some biomass processes actually produce zero net greenhouse gas emissions. This is a definitional problem in the RPS.

The one externality for which policy is still developing is climate charge. This is new, and offers one of the strongest rationales for the RPS. However, if we think about efficient environmental climate policies, the RPS is unsatisfactory. The general characteristics for an efficient climate policy would include all sectors uniformly; be directed at emissions; be market - based, and aimed at creating new technologies that can address the long-term climate change problem. The RPS is local; applies to one sector; and has a technology mandate. Despite the credit trading, it is one step removed from command and control regulation. It provides inadequate incentives for the R&D that we need for climate change. It is command and control because the RPS does not let the market find the best technologies. It forces adoption of a specific one.

Climate change policy does not have an immediate consequence. The consequences extend for centuries. The debate is about how we can stabilize concentrations of greenhouse gasses in the atmosphere. The greenhouse gas concentrations are a function of cumulative emissions in any day or year. They're quite different from criteria pollutants -- for example, ozone -- which depend on emissions from a couple of days before. Stable emissions of greenhouse gases are impossible with current technologies. They require R&D and completely new technologies. One promising large scale technology is nuclear carbon capture. These important R&D needs are not addressed by the RPS.

Let's compare a carbon cap and trade policy to the RPS as a standard for efficiency, I'm picking out one of the many technologies for compliance. If it forces more renewables, then we'll be choosing based on the economics of a carbon cap. It will raise the cost of reducing greenhouse gas emissions unnecessarily. Every time this comparison is done, the RPS has more renewables than cost-minimizing responses. This is consistent in carbon price scenarios ranging from nothing to a rising price that ends at $50 a ton by 2020 or so. The cap produces reductions in emissions of about 10 percent in the high carbon price scenario.

Most of the emission reductions are derived from reduction in coal fire generation; this is internalizing the cost of the carbon emissions; and includes an increase of gas used to substitute for coal. My point here is not to argue about costs, but to argue for a market test, not a political test, of the resource mix to address a carbon reduction.

Let's talk about taxes if we have a national RPS. Generally, wind energy is produced in SPP, and then shipped elsewhere. Texas, Oklahoma, and Colorado have the biggest potential for wind. The Southeast has little potential for wind. Thus, a national RPS will be a tax on Southeastern utilities. They won't be generating it. They will be buying credits because of the regional characteristics.

Two last thoughts on this. One, these problems are associated with design issues for an RPS. Many of these regulations fail to stick to the objective of minimizing the cost of achieving environmental goals. Let's consider the use of Sox, NOx, and mercury permits. It's unclear what the criterion is. An RPS will drive over-compliance with existing regulations, because you have to forsake credits for other pollutants if you're going to sell a REC. Or, the RPS is incapable of producing change in these emissions because if the credits are maintained and utilized by an RPS, the actual RPS has no effect pollutant emissions. It's a consequence of having a technology requirement in addition to emissions trading.

Second, the RPS has produced some counterproductive behavior. Some state RPS' have local sourcing requirements that use the RPS as an economic development tool to promote building of power plants or facilities within a state. It encourages rent-seeking behavior and also some bad economic studies about local benefits. Often this involves people trying to move the RPS in a direction that will benefit their particular kind of facility.

The definition of renewables is also a concern. The definition of renewables and the RPS are not tied clearly to the underlying externalities. Trading renewable certificates cures only one problem, the non-uniform distribution of the capability to use renewables. For example, SDG&E has fewer renewables in its mix. They might find it attractive to buy renewable credits rather than trying to build the power for itself. Similarly, Southern Company, would be better off buying renewable energy credits than trying to build wind in the Southeast in a national RPS. Trading solves that problem, but that's all it solves. There's only a vague connection to the specific externalities. The RPS is not likely to support the most cost-effective choices for these externalities, and doesn't allow superior technologies to be chosen for a specific problem if they exist.

The alternative is emissions trading for a lot of our environmental policies. Trading is efficient when applied without specifying constraining technology standards and when it's applied directly to the source of the externality itself. It controls the emissions we care about; it's comprehensive; and it's unbiased as to the technology or the source. We could define any action that reduces an externality of interest as renewable. That solves the design problem all at once for the RPS. It's tied directly to cap and trade programs for criteria pollutants, which we actually already have, and which need careful attention in order to be designed property.

Finally, for climate change, support for R&D on climate-friendly technologies that can lead to zero carbon emissions for virtually all energy production are absolutely necessary.

Discussion

QUESTION: If standards are explicit, and transmission isn't there, what happens if you can't meet the standards because the transmission is insufficient? There are curtailments and congestion. The facilities may even be there, but there's no transmission. When this happens, what are you doing with ERCOT in terms of the transmission expansion?

ANSWER: We have the ability to suspend the REC requirement. If congestion is preventing the power associated with the REC generation from getting to load, then we don't penalize reps, it's not their fault.

On the second question, we had a case at the Commission where congestion caused wind to be curtailed below generation capacity. How does that affect REC generation? Some said that the REC generation should be what it would have been without the curtailment. It was taken up on appeal, and this position was reversed. It may be appealed to a higher level soon.

QUESTION: The other part of our exchange was that the forgiveness doesn't go away, but the lost credit that betrayed it doesn't get created.

ANSWER: Right.

QUESTION: If there are alternative compliance payments, that forgiveness stays, but the creation of the REC goes away.

ANSWER: There is a difference. Penalties are not typically recoverable from ratepayers, and go to general revenues. Alternative compliance payments are generally considered recoverable costs, and most places also have a mechanism for recycling those revenues back into renewables.

QUESTION: A stakeholder process in ERCOT will be implemented for transmission planning. There is also a mandatory REC requirement that doesn't work unless ERCOT builds very specific facilities. How will these issues be resolved?

ANSWER: A recent piece of legislation gave the PUC the ability to fast-track transmission projects associated with renewables because of this issue. It was done because the traditional stakeholder process at ERCOT was not, some would argue, resolving the congestion problem. It took awhile to get the rule written on this. It is proactive, and gives the PUC wide latitude to reach into ERCOT to remove a transmission project that has been referred to an unfriendly subcommittee or has died for lack of votes. They can force the resolution of that congestion corridor.

QUESTION: There is a concern for the infant industry that hasn't been addressed. We have something that we want to develop. It's not competitive now; it's not likely to be competitive if we don't do something; but it can achieve momentum, and then it takes off. What is the correct amount? 20 percent seems a lot. Is that what we need to cross the threshold for an infant industry?

ANSWER: I have 3 reactions to that. First, the infant industry argument is rarely made quantitatively; it's made qualitatively. Here's something not in the market now; therefore, it's an infant industry and needs to be supported. I'm skeptical of that. It's hard to falsify the infant industry argument. You can get away with it in any context.

Second, there is some data for figuring out how much. While there is significant analysis and experience, there isn't a lot published. The examples I've seen suggest that something happens pretty rapidly at a relatively quick pace. The bigger problem is that a renewables mandate doesn't solve the infant industry problem because the technologies are the ones that are closest to the market. There will be incremental improvements in renewables in the ground, and incremental improvements in everything else, too.

Third, the RPS may not ever drive enough technology improvement to turn renewables into winners. At the same time, the other technologies are improving incrementally as well. The cost of scrubbers has been dropping rapidly as a method for sulfur control. the competition between renewables and other methods of dealing with SOx will stay level.

ANSWER: The infant industry problem is sometimes known as the valley of death between R&D and real commercialization and deployment of new technologies, particularly in markets like energy where development costs are high. However, the RPS is effective and workable when it's done right. There's no magic line between promoting emerging technologies, portfolio diversity, and environmental benefits. Maybe 20 percent is high from the infant industry perspective. Although there's a high likelihood that you see a shift to more biomass, NGO Thermal, and other resources that are moving along the technology curve. In our modeling and EIA's modeling, this shows up strongly as you go from 10 to 20 percent.

It's really a political number in the beginning. Our early analysis showed that a growth rate for emerging renewables of ½ to 1 percent per year for ten to twenty years ought to help them toward real commercialization. Those were the original numbers in New England.

ANSWER: In California, we look at emerging technologies separately from the RPS. There isn't much coordination. We increased ratepayer funding for emerging technologies last year. The state's at $12 million, increasing to $20 million annually. This was done specifically to bring new technologies to market. There is no targeting of the voids in the RPS. That level of thinking hasn't happened.

Governor Schwarzenegger has asked the Commission to investigate a million solar roofs initiative, which would drive a lot of development. Again, it's a program that's being assessed separately from the RPS. Eventually, it makes sense to see how these boxes can fit together more logically on an overall policy basis.

ANSWER: At the Texas Commission, there is no policy position on whether wind is better than other resources. Republicans believe wind is their renewable issue. Rural Republicans love this in Texas. When we think about government initiatives that may be less efficient, this is probably one that's not too bad.

ANSWER: The California approach of keeping technology development separate makes some sense. Just about any renewable technology other than wind that we have today is not the one we want to end up with, especially for climate change and efficiency purposes. Fundamental breakthroughs are needed in a lot of these areas for technologies to work. Programs like Stanford's which are looking at biomass are attempting specific breakthroughs in the fundamental science that would allow for something entirely different. That makes sense. Trying to promote an infant industry and looking at the technology itself are two different things.

ANSWER: There is not problem with R&D for carbon capture and storage, and for advanced nuclear. On the other hand, there's evidence that existing technologies we have can do the job and stabilize carbon concentrations. However, electricity companies aren't purchasing or using them. They're not considering the long-run economics or the externalities. The analyses -- including EIA with their adverse assumptions -- show that even in a cap and trade regime, if you trade away the literal emission benefits, you don't reduce the emissions, but you do reduce the permit prices.

If RPSs increase the diversity of fuel supply, and reduce demand on the lowest carbon fuels, you reduce the price of compliance. EIA's analysis shows that in a carbon-constrained world, the benefits of an RPS far exceed what they are even with no carbon constraints. There's no conflict there.

QUESTION: Do all states with an RPS also have restructuring?

ANSWER: No there are several non-restructured states. It's a mix.

QUESTION: In Massachusetts, there is a renewable energy fund as well as an RPS. They were challenged in the courts in 1997, which is why they didn't take effect until 2003. Have those funds helped develop the renewables that will lead to compliance with the RPS. Should this mechanism be considered by other states?

ANSWER: Yes. There are fifteen states with renewable energy funds, although that number hasn't grown since the first wave of restructuring. In Massachusetts, the evidence is mixed because their fund has a unique structure and approach. It's certainly helping with some siting and pre-development activities there. It is helping to diversify the mix of renewables by ensuring that some solar development continues. Solar will likely be the most abundant and cost-effective resource in New England over the long run, as well as in other places. A new program lets them do the long-term contracts for the RECs, using a portion of their funds and the alternative compliance. They are fixing the lack of creditworthy suppliers, a critical gap in the market. The environmental community spent years debating whether the RPS or renewable funds were better. A combination may be the most effective for encouraging a broad diversity of renewables.

QUESTION: Global climate change is the number one crisis for the world. It's not something we can shove aside, though the country has been doing that for a while now. Would each panelist address energy efficiency portfolio standards?

And on carbon caps, emissions cap and trade, we can't wait for the technology to develop. We need to start it now because Lake Okeechobee could be in the ocean in a hundred years.

ANSWER: Whether we start or not won't change whether Lake Okeechobee is in the ocean. The issue is not current emissions but cumulative emissions over the next hundred years. I know of no long-term scenario for carbon emissions that suggests we reduce emissions immediately at high cost. The tradeoff is between emission reductions available today at high cost, versus much larger reductions that can be accomplished in the future with technology standards.

The various long-term emission scenarios, whether we're aiming for 450, 550, or 750 parts per million concentration in the atmosphere, look pretty much the same. There's not much differentiation in the baseline for the next twenty years. They diverge rapidly as technologies that make emission reductions deployable become available. It's absolutely critical that R&D begin for those technologies, but I differ about the necessity on timing.

Bottom-up policies take a lot of effort for emission standards. They target specific actions, and miss everything else. Combining an efficiency standard with a renewable portfolio standard is backing into putting a price on carbon and letting that find its way through the economy, and figuring out a way of stimulating long-term R&D. Some developments in the RPS are working towards this goal, and towards the right economic incentives but they just bring us closer to an overall cap and trade system. Building up one kind of technology or sector or standard doesn't lead us toward that. The market could find a lot more with an overall cap and trade system.

ANSWER: Energy efficiency performance standards should be workable. Pennsylvania will be an important experiment. They have it in a separate tier. It's got to compete with other things. However, mixing too many different things together may not help more than one or two at a time. Renewables have some common characteristics. Wind is the big winner early on, but we are getting some diversity. Energy efficiency, and combined heat and power are clearly cost-effective on their own, but face critical market barriers. It's not clear that you can get both renewables and efficiency from a combined standard at the same time. Certainly the efficiency standard alone is promising.

QUESTION: Can you address the science issue?

ANSWER: On the carbon issue, I've seen some exact opposite conclusions. No surprise there. The vast majority of climate scientists working on this problem are concerned by new evidence that it's carbon concentrations. This evidence shows that carbon concentrations exceeding 450 parts per million are 50 percent more likely to raise global temperature by more than 2º Centigrade. Most climate scientists believe this is the threshold between moderate and really severe climate impacts.

We're at about 380 parts per million now, and increasing rapidly. If we wait until fourth-generation nuclear power plants are available, achieving 450 will literally be impossible without overnight carbon reductions of almost 50 percent in emissions because we will already have achieved those carbon concentrations in the atmosphere. Every year of delay means that the curve for reducing emissions gets steeper and more expensive. A wide range of analysis shows that early reductions, particularly when they are cost-effective for other benefits, are far more economic than waiting for new advanced technology.

ANSWER: In California, the energy agencies adopted an Energy Action Plan in 2003, and it has a loading order that places energy efficiency first. We don't combine energy efficiency portfolio standard and renewable, and have some sort of competition. However, there are ten-year energy efficiency goals for our investor-owned utilities, with annual targets. Those targets are in reach with current funding. The targets are taken off the top and then renewables are next in the loading order. It's similar to our renewable portfolio standard. We are probably overly complex, but there's clarity about our process and priorities.

In climate change and carbon policies, the California PUC has been a national leader. In December the PUC addressed carbon as a policy based on clear scientific evidence. We have a carbon adder. We are also looking at a cap and trade system.

ANSWER: There is a major scientific study coordinated by the California EPA but with PUC involvement, and other resource agencies assessing impacts from climate change on California industries and California's resources. There's extensive concern for significant impacts on our economy and our industry. There may be vast change in our Sierra snow melt. The first stage of the study is coming out in January.

QUESTION: In California, the assigned cost is eight dollars a ton for carbon. It's somewhat random. It's got regulatory risk in it. Why not link it to something that is tradable and hedgeable? Make use of the existing number, which is eighteen euros per ton right now, probably above nineteen in the long run. That's a relatively small step. Maybe this is politically naive, but the biggest step would be for a state to join the Kyoto Protocol. It doesn't have to be done federally.

With cap and trade you've already got an existing infrastructure focused on offering trades around this product. There would no incremental cost if allocation of allowances was benchmarked to the reduction goals. You don't have to assign credits the way others have; you could auction them off and use them to balance the state budget. Why there hasn't been more state-level focus on that?

ANSWER: The Commission has had a review for almost a year now, but there is some question about their legal authority to impose this. If the Commission does go this route, they're only picking up the investor-owned utilities and leaving out 20 percent. Further for the political discussion is that they're only dealing with the electricity sector.

ANSWER: A state can't do it is because it's not allowable under Kyoto. The Protocol sets up national allocations of emission targets. Only international trading of those national targets is allowed. The national governments can set up procedures under which legal entities within those countries may trade under that authority. The United States has to be a party to the Kyoto Protocol, and set up an emission trading system. The EU hasn't decided whether they'll allow purchase of credits outside. Even if they did, they could only do it through other national governments participating in Kyoto.

COMMENT: Something like 174 cities have committed to the Kyoto reductions. With Republican and Democrat mayors across the country.

COMMENT: The northeastern states, New England and Delaware and New Jersey, have the regional greenhouse gas initiative. Obviously, it's bipartisan.

QUESTION: The last speaker's presentation was compelling but the argument isn't winning. Here are some reasons: People don't buy the argument, or the caps are too high and we can't get them down for political reasons, or it's just that a multi-front attack on this problem is better than anything else, or we can't wait for the economic process to work; we just get too nervous. Can you talk about why this approach isn't convincing people. Could the third speaker explain why he isn't selling you his arguments?

ANSWER: Why aren't strong economic principles used in design of our environmental policies? I don't know. It's been an uphill battle but there have been some successes. It means fighting against current fads in policy and entrenched interests. These interests are seeking rents they couldn't get if there was an economically efficient design for a program.

ANSWER: We're winning because we're right, of course. Reducing carbon emissions is the lowest among the drivers for adopting renewable energy policy. People are concerned about it, yes. There are local development opportunities that are important to Republicans and Democrats. People understand that this is energy from the sun that arrives every day; you don't have to scrape it out of the earth; most countries and regions have similar amounts, potentially reducing international conflicts and energy insecurity, There's no fuel cycle of impacts, waste storage, or safety risks.

Wind kills birds, but fewer than automobiles, transmission lines, and buildings. If there was a 100 percent wind economy, we'd be killing fewer birds from wind than from other human sources combined. These technologies are attractive for a whole host of reasons. This is the first time I've heard an economist argue it's more efficient to address each individual externality one at a time rather than trying to avoid a whole range of pollutants by preventing their production at the source.

QUESTION: there are several motivations for renewable portfolio standards beyond environmental protection. In New England one driver is resource adequacy or fuel diversity. The region imports most of its fuels. The energy security benefits help hedge risks against fuels that have a long delivery chain. A distaste for technology standards, of which the RPS is just one illustration, has been discussed. Is resource adequacy a better reason for a technology standard, or is problematic for addressing that externality?

ANSWER: The real question is what the market can handle, and whether government at any level needs to step in. Resource adequacy is not addressed by mandating renewables or anything else. I'm not sure it's a real problem. The market addresses resource adequacy well. Utilities are motivated to balance the costs and risks of the supplies that they are purchasing. They assess long-term and near-term costs of coal, renewable, and other resources. Imports are not a bad economic choice or something to be avoided. They need to be factored into the equation for determining the optimal resource mix. There is a difference between concern over future natural gas or coal prices versus requirements for the production of particular fuels. The only real public policy issue for New England is natural gas imports and LNG. The utilities can make effective decisions for their consumers without help from an RPS to tell them where they ought to find the power.

ANSWER: During legislative sessions in Texas there was an argument that we needed wind to ensure generation supply over the next forty years. There was genuine disagreement from the system operator. Wind is not dispatchable, it's off-peak – it's a less reliable source for reliability. It's nice for diversity purposes but we can't rely upon it for dispatch.

However, we ran the policy experiment with a small amount of wind. Every constituency group likes it, with the exception of large industrials because they consume so much power, and every small amount of cost is meaningful to them. However, even the industrials have gotten involved in the debate over assuring supply. This resource adequacy argument was run up our flagpole, and nobody saluted it.

ANSWER: From a capacity-only standpoint, wind is not dispatchable. Its capacity value varies by region, depending on the resource and load match. However, it's not a reserve margin solution. For New England, renewables look like they can make a major contribution to the natural gas adequacy and imports issue.

QUESTION: What are the assumed costs of this program by the Commissions? What about alternatives? In the United Kingdom, new investment in nuclear has been off the table for the last fifteen years. Now, the government is being pressed on the cost of the renewables program, and it's high. Although nuclear is assumed to be more costly and risky than conventional generation, it looks less costly, risky, and problematic than renewables. There is speculation that the UK government will soon propose to put new nuclear on the table. What are the Commissions in the United States thinking about this choice?

ANSWER: In California a 35-year-old law prohibits the building of new nuclear power plants until there is a federally-approved method for the long-term radioactive waste storage. We're probably not going to see new nuclear power plant proposals in California anytime soon.

QUESTION: Some clarifications. There are twenty-one states and a district with RPSs and if you count California, with suspended retail access, it would make fifteen of twenty-one RPS states that are restructured. Second, the description of generation in West Texas traveling six hundred miles to meet load sounds much like yesterday's discussion of Argentina. That's just an observation.

Good modeling is critical, especially when decisions are made by policymakers. The EIA analysis of the Bingaman Amendment had a fatal flaw from the National Energy Modeling System, which led to misleading results. The NEMS breaks the country up into thirteen regions similar to NERC regions. The model assumes that each region is a single utility which is a problem. Second, 90 percent of renewables were being built by merchants, not utilities, over the previous ten years. Third, if an LSE or a utility was short on credits, they would have to buy credits from the Secretary of Energy at a set price. If the overall supply in a region was not as high as the RPS requirement, the merchant generators would charge the full credit price in a market, if they knew that that was the ceiling. This would create a large flow of money to the merchant generators, equal to the RPS megawatt hours times the credit price. By assuming that each region was a single utility, the NEMS model implicitly assumed that the credits and debits would balance out. Retail consumers would wind up paying, not in present value but in stock terms, about ten billion dollars extra under the Bingaman amendment.

Further, since merchants would be taking excess profit from the credits, and the utilities would have to pass that excess profit through to retail customers, the real impact for retail customers was about $100 billion higher than the NEMS model predicted. This is simply because the structure of the model did not recognize the corporate structure in the NERC regions. The policy recommendations were based on flawed accounting. It's important that we critically look at the models used in the policy debate, and make sure that the real costs to consumers are carefully reported.

ANSWER: Every model has its flaws and its simplifications, and NEMS is certainly no exception to that. If you assume prices will automatically rise to the cost cap, then you certainly get a higher cost than the model. If the target is too high, there are supply shortages. However, the modeling shows that prices won't rise that high. It's certainly far from the case in Texas. The utility's analysis multiplied the penalty price times the REC price, and that's what the RPC would cost. It's a lower number than you're citing. NEMS also has many simplifications of weaknesses that are not biased against an RPS analysis. You have to consider both.

QUESTION: One utility wanted to roll the cost of transmission into overall rates instead of applying the current FERC policy, which says that if a proposed line is a radial line, it ought to be allocated to the generators. In Texas, all these things will be rolled in. Happily, you've got a Texas policy that says, "we want renewables." ERCOT was able to decide to make the policy consistent with that. When Texas was considering the proposal to roll it in, was it a critical component to get the wind developed there? Were generators saying, "We're not going to build unless you roll this stuff in"? That's what we're hearing in California, and I'm wondering if Texas went through this issue.

ANSWER: My understanding is that policy on uplift for transmission enhancements preceded any discussion for wind interconnection. That was the ERCOT policy, and had been the policy back when there were multiple operating zones. When ERCOT was collapsed into one region, stakeholders decided they wanted to continue that way. It was more of a questions of wind generators understanding ERCOT transmission policy, and then using that to their advantage.

There has been some debate about whether we should change that policy. There was a recent bill that would have required any new generation, not just wind, to pay a certain portion to interconnect. It never got out of committee.