

**Harvard Electricity Policy Group**  
**Special Session**  
Taubman Center, Kennedy School of Government  
Cambridge, Massachusetts  
November 30, 2001

**RAPPORTEUR'S SUMMARY\***

**Session One: Standard Wholesale Market Design**

*The decision by the Federal Energy Regulatory Commission to accelerate implementation of Regional Transmission Organizations includes the rulemaking on standard market design. To some, this reflects a commitment to finish a gradual convergence. Or the rulemaking could be viewed as drawing the lessons of experiments and implementing best practices. Others would see an inappropriate or, at least premature, abandonment of regional experiments. The challenge is to improve the dialogue as we move below the level of broad principles to the details of market design. With regional markets at different levels of development, it will not be an easy matter to move everyone to the same place or at the same pace. Further, although the Federal role does not include jurisdiction for retail markets, there is an inherent necessity and obligation to ensure that wholesale and retail market designs are compatible.*

**Speaker One**

I have three messages. The first is that we have to come to terms with the fact that FERC is developing a system of franchises that it calls RTOs that are going to be in place around the country. We need to think about the RTO as a franchise, and not just as a modest little organization that's going

to be doing just a few things to help us out in the electric business.

The second message is the continuing importance to our nation of customer-based, distributed energy resources, distributed generation, energy efficiency, load management, price-responsive load. We spent a decade learning how important those resources were, and then spent the last

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

five years or so just walking away from them.

The third message is to assert that FERC has an obligation and an opportunity to develop market rules and structures that will reveal the value of those resources and call them forth for the benefit of our markets, economy, customers and the nation. It's not just about price-responsive load. There are a lot of customer-based resources that we ought to be addressing.

I've participated in discussions, as many of you have, over the geography of proposed RTOs, and those debates have been pretty hot. But the real issue is market structure. The benefits to the nation are going to be much more significant in getting the market structure right than they are in trying to figure out the perfect geography for the RTO franchise.

FERC is paying a lot of attention to the functions of an RTO. Just and reasonable rates in a market-based system which is what the Federal Power Act calls for are not going to be possible unless you have a complete market, and you don't have that unless you have an active demand side. Transmission tariffs and ancillary service charges will be unreasonable if the costs that are imposed on ratepayers in a non-bypassable way are not screened for least cost. We have a problem that I call the demand side vacuum.

Since the mid-90s, integrated resource planning basically became moribund. In California, restructuring efforts took functions that used to be part of the

integrated franchise and pushed them up to FERC, and FERC has not yet really known what to do with them. FERC and the RTOs, of course, have no traditions concerning the demand side, and so it requires a new, evolutionary process for them to figure out what it means to involve the demand side in their work.

There's also the problem I call mutual blockade. We're developing retail and wholesale market rules and transmission rules. Unfortunately, the two are not always well combined, and we end up doing things at the retail level that block the efficiency that you might get in the wholesale market, and vice versa. It is important to remember how important the demand side is.

Reasonable projections based upon both technical and economic feasibilities suggest that 30-50% of the load growth we're now struggling to meet nationwide could be met through customer-located distributed resources. It's not just price-responsive load, but that would be an important part. Energy efficiency, load management, distributed generation and combined heat and power represent a huge potential low-cost resource to the nation. Lightening the load improves reliability all across the grid. It's worth noting that it would improve as well our new focus on meeting the nation's energy security needs. And of course, provide environmental benefits at very low costs.

In California, we know that they did almost none of this. The wholesale market didn't have an active demand side component. It's less well known that California actually dramatically

cut back its investments in energy efficiency in the years following its approach to deregulation, and that contributed something like 1100 MW of lost savings that exacerbated their problem significantly.

In the prior decade, we learned that the energy efficiency side of things consists both of demand management and load management, and reductions in consumption across the board through embedded improvements in the efficiency of technology that was deployed throughout the economy.

At the retail and wholesale levels, we suffer from two barriers: there are the historic market barriers to energy efficiency that we all know and have come to understand, like the so-called split incentives problem that the people who build buildings pass on to people who pay the electric bill, for example, or the discount rate problem, or the problem that customers have getting enough information to make investments in energy efficiency that would be cost-effective. In addition, we decision-makers in the electric industry are creating additional barriers to the cost-effective deployment of demand side resources. Almost nowhere at the retail level do customers see real-time prices. Not only that, we provide default service plans that affirmatively protect customers from seeing real-time prices. I'm not going to jump to the conclusion that we should require all customers to see real-time prices, but it illustrates that we have to come up with a way that the load-serving entities can see real-time prices and see the value of improvements in load shape.

At the wholesale level, we're doing some of the same things by creating markets that have only supply side bidding; by allocating power costs on a settlements basis that use load profiles that don't reward load-serving entities for improvements that they make in the load shape of their customers; by creating reliability rules that don't allow demand side resources to bid evenly against supply side resources to provide ancillary services to the pool; and by subsidizing a variety of historic, and some new and clever investments in transmission, reserves, and supply side in ways that are not available to demand side or distributed resources.

Fortunately, FERC is coming to terms with some of this. FERC is now very clear in understanding that a demand side in the market is essential to the creation of a sound market structure.

I speak from experience as a state regulator who tried pretty hard over the course of a decade to integrate demand side resources into the electric system in a variety of ways. For example, there was the design and implementation of a variety of DSM programs. There were many hard looks at rate design. We had to deal with the problem of lost revenue recovery for utilities that engaged in demand side work. The concept of least costs and exposing the value of demand side resources came up in siting reviews when utilities were proposing to make major power purchase decisions. There are a lot of places where these resources have value that has to be exposed.

Now I'll show you where FERC ought to pay attention and act in order to call forth those resources. I'm going to pass over demand side bidding and reserves because I think you really know that, and with this audience, it seems almost superfluous to talk about multi-settlement markets and congestion pricing.

However, load profile is a problem with respect to the way, for example, that default service load is assigned in Massachusetts, where responsibility for load is assigned using load profiles in wholesale settlements. Because individual customers are not real-time metered, there are assumptions about their load profiles when the power costs are assigned among LSEs at the end of the month. If you don't create new load profiles when load-serving entities improve the load profiles of their customers and give the entities the benefit of that profile, you are undermining any incentive to improve their customers' load profiles. It's my understanding that this is the problem with default service loads in Massachusetts today, and it's also happening in virtually all wholesale markets around the country.

Not all ancillary services can be provided by demand side resources. We ought to create technology-neutral bidding rules so that demand side resources can bid to provide those services to the pools. And real-time metering for very dispersed loads like a ripple-controlled or a radio-controlled air-conditioning load management program don't need to be required to assure reliability if you can statistically verify their performance. Transmission congestion pricing is

necessary in order to reveal the value of distributed resources in locations and in hours when they provide significant value to the grid.

We now have a new problem that we're going to see coming up in different places which is the rolled-in facilities cost-recovery problem, where generators can locate pretty much anywhere they want, make their own locational decisions, and then transmission is built to support that. But that generation isn't asked to pay for the cost of that transmission; instead, the costs are rolled into everybody's transmission rates. We create a market that tells generators, "Locate where it's good for you to locate, regardless of the costs you're imposing on the system." This also has the effect of undermining the value to distributed resources that are located in the load center. Not only are you subsidizing generators and encouraging them to locate irrespective of the costs they're loading on the system, you undermine the market you're trying to create by promoting competition for distributed resources. And that leads to the efficient reliability rule. We need to look at the places where, without necessarily even knowing we're doing it, we socialize the costs of a proposed reliability-enhancing investment through an uplift or a tariff.

These things often come to us in the form of, "It's for reliability and therefore everybody ought to pay for it." That might be true on the surface. But what if the same degree of reliability could be obtained some other way? There ought to be a requirement that before someone can

use the wires to load their reliability proposals on captive ratepayers who have to pay transmission charges, a hard look be taken at the proposal and that lower-cost alternatives have the opportunity to provide a solution.

Wholesale and retail connection: As I said earlier, I call this the potential mutual blockade. In designing a demand side portfolio for both FERC and RTOs, we need to consider the connections between the retail and wholesale markets. Price signals and incentives have to flow up and down the chain all the way from producers to customers. Right now, there are a lot of barriers.

To deal with those barriers, in this region there is the New England Demand Response Initiative. It's a facilitated stakeholder process now being launched that involves utility regulators, the ISO, environmental regulators, and the support of DOE and EPA. We will also be inviting PJM and the New York ISO to collaborate with us as we examine all of the ways in New England that demand side resources and distributed resources could be tapped cost effectively to provide energy services. The principal goal is to examine the potential across the region, and in depth from retail through ISO to wholesale, look at transmission and markets, and come up with good proposals we can suggest to decision-makers.

FERC has this opportunity and, I believe, the legal obligation to examine and reveal the value of demand side and distributed resources throughout the system. As state regulators and market participants, we

have the obligation to work with them to create policies that work from the retail to the wholesale level.

## **Speaker Two**

As a utility executive, I will talk about the role of transmission in competitive wholesale markets. I begin with the cost of congestion on the transmission system. If one takes an unconstrained transmission system, and takes a least cost, bid-based generation dispatch, which means not least cost in the traditional sense, but a market that people bid into at the prices at which they're willing to sell power. The system operator stacks the bids and says, "I'm going to dispatch the generators based on those that are willing to provide at the lowest cost up to the point where you've got supply meeting demand." You have a totally unconstrained transmission system and you dispatch the system. This way, you've got a certain cost which consumers in the region pay for electricity.

Now change the paradigm. You've got constraints on the transmission system. The system operator says, "I see I can't dispatch the generation the way I would like. I've got to turn off or ramp down some generation that should run because it's willing to provide power at a lower cost, and ramp up or turn on generation that is in the right location on the system," meaning on the side of the congestion interface that's congested.

As an example, Boston has generation that's low cost outside of Boston, while generation inside tends to be

higher priced. You have a situation where the system operator says, "If I could dispatch the system based on lowest cost to consumers, I'd run a lot of that generation outside of Boston. But I can't get all the power over the transmission system, so I've got to ramp down some generators outside and turn on some more expensive generators inside."

The difference between what consumers pay for electricity, either because of uplift charges, or because those charges are reflected in the locational marginal energy prices -- the difference of what they pay on the congested system versus the uncongested system is what I refer to as congestion costs. In simple terms, customers pay more for electricity than they would on an unconstrained transmission system. And these are the annual prices, about \$150 million in New England last year. My understanding of the annual revenue requirement statewide for transmission in New York is about \$800 million. If that is correct, consumers are paying more in New York for transmission than they don't have because of congestion on the system than they're paying for the transmission that is in the ground.

Having just defined congestion as bad because consumers are paying more, let me round out the picture by saying that congestion is not necessarily viewed as bad by everyone. Some generators make money off congestion. If you have a generator located on the congested side of an interface, your generator is running more, and you're getting higher prices for your power than you would if the

constraint were alleviated and the low-cost power could flow into the load center.

Second, to the extent that there is congestion and you create price differentials on either side of the transmission line (high prices here, low prices there, and power cannot flow), you in fact create opportunities for merchant transmission providers. The more the congestion and the greater the price differential, the greater the opportunity for someone who's in the business of merchant transmission. It's a profit opportunity for merchant transmission developers.

I want to talk about policy solutions and about process solutions. Locational energy pricing could not come to the temple of locational marginal pricing without first talking about locational marginal pricing as sending the right price signals to the market. Where you have a congested interface, locational marginal pricing does give market participants price signals. Prices are higher on the congested side of the interface, and lower on the uncongested side.

Second, transmission rate design, or license plate versus postage stamp pricing, using New York as an example: My understanding is that under the rate design in New York, a number of the constraints that impede the flow of power south exist on upstate systems. To alleviate that, construction would have to be made to enhance interfaces upstate. Under today's rate design, those costs would be allocated to the transmission owners and their customers in that area. So the costs go to one group of customers and

the benefits would largely go to downstate customers. License plate rate design creates a disincentive to transmission owners who could take action to relieve constraint, because prices to their customers go up, and prices to others in another location go down.

One answer might be postage stamp transmission pricing where you alleviate the constraint but your customers aren't going to pay it all. It's socialized across the region. However, that introduces another imperfection: whenever you socialize prices, customers don't see the true economic impact of the decisions being made.

The elegant economic solution would be to allocate the transmission costs to the customers who derive the benefit. But where you have a transmission upgrade that has reliability benefits and economic benefits, the economic benefits may well change over time as new generators come on. It is not easy to map the benefits to particular customer classes. That's a quagmire when you come to rate design, with everybody fighting that it benefits them more than me.

Market response or regulated transmission for congestion relief: I suggest that one need not, as a policy maker, choose; that there's the potential to have a system under the RTO as we go forward where we could tap into both market responses for alleviating congestion and regulator transmission for congestion relief.

Reliability versus congestion needs: Whenever you have a transmission

upgrade on the network, there are likely both reliability benefits and economic benefits of alleviating congestion. It's difficult to separate cleanly a transmission upgrade as to *this* is reliability and *this* is economics. In many cases, it's both.

I'd like to suggest a framework for consideration for transmission planning as we move into RTOs. Consider the RTO implementing a process that begins with a plan that looks forward, say five years into the future, and takes into account demand, meaning what the load is likely to be. It involves load and generation forecasts, and equally important, what generation may close for economic or other reasons and where, and what the impact will be on the system. What transmission upgrades will be planned? These are both merchant projects and regulated projects that are moving through the pipeline.

All of this enters into Step 1, which is a needs assessment. When you account for the likely load and supply, then you develop a picture of the needs of the region going forward. Is there enough transmission capacity, too little, either for reliability reasons or for economic reasons?

Step 2 is the regulated transmission backstop. By that I mean to the extent that there's a need, what steps and what projects would the regulated transmission entity take to alleviate the reliability or congestion problems on the system? Those steps or facility upgrades would constitute the regulated transmission plan and take into account what the market is doing, but saying if the regulator transmission

entity has to respond, these are the steps that it could take to alleviate the reliability problems and to address the economic congestion issues on the system.

Step 3 would be a very open, public review of the plan. In fact, open and public really applies to this whole thing. The transmission planning process will benefit by having a very open process where everybody's able to participate.

What next? To the extent that you're doing a plan, and it has a planning scenario looking out a number of years, you have just given information to the marketplace that it is going to be congested here, and there is an opportunity for market-based projects to remedy the problem.

It could be a new generator locating on the congested side of the interface, or a merchant transmission developer stepping up to say, "I'm going to build my line to take care of that congestion problem." To the extent that the market is given information and it responds, then the problems are taken care of, and the regulator entity need not then say, "I'm building the regulated project."

But what happens if the market doesn't respond? I don't think we can assume in all cases that the market will address each problem that's identified on the system. There needs to be someone who in the public interest says, "We will build the facility that's needed, either for reliability or to alleviate congestion on the system so that consumers aren't paying congestion costs that could be alleviated." That, I

believe, is the role of the regulator transmission entity under the RTO, to step forward and do those market-based projects.

This chart reflects a forecast of the transmission situation going into northeastern Massachusetts and Boston over the planning period 2002-2006. The green line shows the transfer capability, how much power can flow over the interface at time of peak demand. The blue represents a deterministic forecast of how much power is likely to flow at periods of peak demand. This is a load forecast and a projection of the load in a given year, taking into account generation that has been approved to come on line in New England. It takes into account transmission upgrades that have been approved to go forward. This shows the amount of power we project will actually flow into Boston at peak demand periods in each of those years.

The bandwidths are probabilistic analysis. We've taken the blue line and said, let's change it. Let's look at it for different scenarios of load growth, for different scenarios of generation coming online, different scenarios for generation going off-system and we've done a probabilistic assessment. The red reflects the flows over the transmission interface into Boston under 50% of those scenarios. We ran roughly 1,000 scenarios. The yellow reflects 90% bandwidth.

In short, during periods of peak demand over the next several years, we're looking at transmission flows into Boston that are likely below the transmission interface. That's good news because in the past, Boston has



been the most congested interface in the region. Looking forward, we believe during peak conditions the interface will be able to accommodate the power flows.

What's happened? One, there are about \$35 million of transmission upgrades being built by the regulated transmission providers in the region today. Two, a new generating plant is coming on line inside Boston next year. The combination of one market-based project and one regulated project is addressing what has been the most significant congestion issue in New England.

A different scenario is a transmission constraint that's just north of New York City. It shows that there's going to be a big gap between the existing transmission system capacity and the forecast, and there is likely to be very significant congestion on the system in New York. This reflects high congestion costs to customers in New York. This information to the marketplace says there's an opportunity here to do something. To the extent the market steps forward, then consumers will pay lower costs. To the extent it doesn't, I would suggest there's a role on the part of the regulated transmission providers to do something.

Why be concerned about congestion? To the extent that we take actions to reduce it, congestion enlarges the size of the market. You've got generators located remotely from load being able to sell into the marketplace, and generators located on the constrained side of the interface. You can reduce spot market prices because when you

have a congested system, you're essentially taking generators out of the market. They cannot reach and sell power into the region. When you have more sellers participating in the marketplace, you reduce spot prices, which also reduces bilateral prices going forward because when sellers enter into bilateral contracts, they look at the options that people have to buy power from the spot market. It reduces market power. When more power flows in, to the extent a generator has market power in a region, that's diminished when more sellers are able to compete, and it removes uncertainty in the market. Finally, when some of the generation located in the congested load pockets is older generation and some of the generation being built outside the region tends to be natural gas-fired and cleaner, there may well be an environmental impact.

Transmission, I suggest, is the highway to enable competition to occur in wholesale markets. The benefit that restructuring was intended to deliver to consumers is delivered, but satisfactory transmission infrastructure is key. In conclusion, as we think about models for the RTOs, I recommend that we consider a for-profit, independent transmission company as part of the RTO structure.

First, the for-profit, independent transmission company is very consistent with the planning model I've just talked about. It can coexist with a PJM-type market design. It can coexist with locational pricing. It is consistent with financial transmission rights and with merchant transmission development. It introduces into the RTO design an entity that's in the

business of transmission. Its business will be to do the type of planning that I've talked about and to provide information to the marketplace. To the extent that the marketplace doesn't respond, its business will be to invest in transmission and to take actions that will alleviate congestion.

I said it the way I did because they're not identical. Investing in transmission is one solution. There are operational practices that a transmission provider can also take to alleviate congestion. And the transmission provider being in the business of transmission would have at its disposal both the investment option, as well as what could be in operating practices to reduce congestion.

With the appropriate incentive regulation where the transmission provider has the financial incentive to reduce congestion on the system, it will have the opportunity to examine to what extent congestion can be eliminated: by investing in hardware; by taking other operating actions; and if one is lower cost than the other and its profits are tied to the amount of congestion that it's able to reduce on the system, it has the right economic incentive to find the lower cost solution to alleviating congestion.

This type of congestion incentive is not untested. In fact, it is what the regulator in the UK agreed to with National Grid Company in the mid-90s. When the markets opened in the UK, much as when the markets opened in New England, New York and in PJM, congestion costs increased significantly. What National Grid and the UK regulator agreed to was a target

for congestion costs. Given prudent utility operation, much as it had operated in the past, what level of congestion would we expect to see on the system? The regulator told the company that if it reduced congestion below that level, there would be a sharing between shareholders and customers of the benefits. If congestion increased, shareholders and customers would share the costs. The company was financially incented to manage congestion on the system.

National Grid did so through targeted capital investments on the system, changes in operating practices, the introduction of new technology and the increase in the capacity of existing transmission interfaces.

The right financial incentives for creating a for-profit entity as part of our RTOs would include the regulated backstop, but also actions that will reduce congestion on the system to the extent that market participants have not. We will provide a system that will facilitate vibrant wholesale markets and deliver benefits to consumers.

## **Discussion**

*Question:* You said that reducing congestion removes uncertainty in the markets. For whom did you mean?

*Response:* I meant for everybody, but particularly both for sellers and buyers of power. To the extent that a seller for power is looking at the marketplace and is in a position where it says, "I don't know what congestion is going to be on the system, and some of those costs may be coming back to me, I've

got a load obligation and I've got to sell power, then how do I end up as a buyer of power in that situation, determining the ultimate costs that I'm going to have to pay to be able to serve my load?" There's a great deal of uncertainty there. The seller on the other end says, "The buyer doesn't know what the ultimate costs are going to be because the system is constrained and it's got to absorb congestion costs and that uncertainty is going to be reflected in its willingness to pay a higher price, and sellers are able to offer higher prices because of that uncertainty." To the extent that there's little congestion on the system, buyers have a better indication of what their prices are. Then you take that uncertainty out of the market and the uncertainty premium comes out of prices.

*Question:* I couldn't tell if you meant that a for-profit ITC would operate a PJM-type market. What do you mean by the ITC would change the operation of transmission or operating protocols?

*Response:* The ITC could, but need not, operate the markets. If it operates the markets, it's a transco. It's essentially probably doing all of the functions that FERC has set out in Order 2000. It need not. You could have a system operator, and I'll use New England as an example: the RTO filing made to FERC last January contemplated an ISO operating the markets and an independent transmission company. Where the ITC is not operating the markets, the type of actions that it would take would be on the transmission system. For example, coordinating transmission outages so that you don't have

multiple transmission providers taking outages at different times that result in congestion in the system; coordinating transmission outages with generation outages; maybe entering into a contract with a generator that was on the constraints side of the interface saying, "You know, if you run during this peak period of time when the transmission line is going to be out, then we can reduce congestion costs." The transmission provider could enter into a contract with a generator for that period of time. If it is operating the markets and operating the generation dispatch, there are more opportunities because now the ITC would also be re-dispatching the markets. I think the potential pool of savings becomes greater. But you can do it under either structure, and I think that will be dictated by local preferences and what institutions are already in place in the various regions.

### **Speaker Three**

This schematic of the Neptune regional transmission plan has been approved by FERC. The plan entails high-voltage DC interconnections between different points. Phase 1 entails the interconnection of PJM with New York City: 1200 MW out of PJM, 600 into New York City, 600 into Long Island. Phase 2 entails 1200 MW out of New Brunswick into New York. Phase 3 entails 1200 MW out of Nova Scotia into Boston. Phase 4 entails 1200 MW out of Maine into southwest Connecticut. The nature of DC is that once you have this system in place, you can move power from any one point to any other point. What we have created is a system that is undersea, so

it parallels the existing AC grid that has what you might call 4800 MW of transmission service rights. I'll show you the implications for the Northeast RTO as we go forward.

The system has a couple of central points. One is that there are places in the northeast where power is cheap to generate, such as in Canada where you can run the Nova Scotia shelf gas net of tariffs through an efficient generator and move the power through our system competitively with the movement of gas down a natural gas pipeline. Neptune also interconnects to urban load pockets that are difficult to serve with existing generation plants. It is extremely difficult, as you know, to site a merchant genco in Boston or New York City. If you think about merchant transmission in this particular system, ask what you would be willing to pay to be able to permit a 1200 MW power plant in these locations.

HVDC is not new. Worldwide, there are dozens of projects. I think it's fair to say that HVDC constitutes the backbone of a very successful pool in Europe. This is existing technology whose place has come in an era of location marginal pricing. The Hydro-Quebec and DC hydro lines come into US markets. TransEnergie's Cross Sound cable is permitted pretty much. This decision by FERC was the one that paved the way for the decision it made for Neptune a year later. The Trans America grid proposed by Siemens and Black and Beech is an even larger system than Neptune. It would interconnect the eastern and western interties. There is also a Northeast Utilities project that would

interconnect southwest Connecticut with Long Island.

Neptune filed its FERC application on May 23, 2001. FERC approved the filing on July 27. This was an impressive display of FERC's desire to see merchant transmission move forward. FERC granted the right to have an open season for the allocation of capacity rights -- the right to base rates on the outcome of that open season. This is not a cost-plus deal, this is a market deal: the right to have a secondary market for the resale of capacity and the right to finance the Neptune system on the back of the long-term bids and contracts from the marketplace. The open season began September 10, and the first round has been completed and the bids are being evaluated. They are quite complex.

FERC authorized and actually required integration of operations with the northeast RTO. We have signed an MOU with PJM, and have begun the process of discussing exactly how to do that. A July FERC order required a northeastern RTO to allow for merchant transmission by non-traditional owners.

A TSR is the right to use the capacity of a system from one specific receipt point to a specific delivery point. It is a point-to-point right that is obviously difficult to get in an AC world, but is not difficult to get in a DC world. A TSR can be taken down to one MW. The duration of a TSR can range from one hour to over 20 years. It is designed to be as flexible as possible. It can be bought and resold, subject to the continuing obligation of the successful bidder to pay the contract

price. TSRs can be recombined into different pathways than the one originally purchased in the open season.

There is no single value driver behind a project like Neptune. It's a basket of different things that a bidder might be able to obtain. These are somewhat notional numbers, but I think directionally they are correct and in order of magnitude, they may be correct, subject to some of the regulatory uncertainties to be resolved.

There is a fuel cost advantage that some of the bidders located in Canada will have. A Nova Scotia generator pays for gas without the Maritimes or the Northeast pipeline tariff. That's a dollar and a quarter tariff per million BTUs, an eight- or nine-dollar cost relief, if you will. New Brunswick has existing generation using coal or emulsion nuclear, and its fuel cost advantage vis-a-vis a generator in New York City could be quite significant.

There are capital-cost advantages. Obviously, it's cheaper to build a generator in Nova Scotia or New Brunswick than in New York City. There are also avoided LDC charges. There are differences in internal transmission charges that have yet to be resolved by FERC. There is no in-city interconnection cost that you have to pay in Maine, New Brunswick or Nova Scotia, whereas the interconnection cost for a new genco in New York City can be \$50 or \$100 million, or another very large number. There is no summer derating for generators in Nova Scotia or New Brunswick, as in New York City and in PJM.

On the revenue side, there is an issue of how enduring the urban premium is. This is the congestion issue we've been discussing. How big will it be and will it remain over time? Ten dollars is a reasonable number for New York City congestion costs today per megawatt hour. How much will that go down as projects like Neptune or in-city generation get built?

There is a portfolio value, too. The ability of a New Brunswick generator to sell to three or four markets has to be monetized. There is an ICAP possibility: you can sell ICAP and ancillary services in New York, even though you are based in New Brunswick or Maine. There's a volatility value -- the ability to sell options in markets that are volatile if you're located in a market that is not.

What are the challenges? What exactly is merchant transmission? How do you develop a merchant transmission project? What are the economic, regulatory and market problems? How do you deal with the equipment suppliers? This is not the world's most liquid market. What kind of competition is there?

The natural areas where merchant transmission developers are going to be pulled is where there's stranded energy, so Hydro-Quebec's push of HVDC out of its very efficient baseload hydro systems is a classic. Natural Gas Offshore Canada, the gas resource in the Scotia shelf, may be 100 TCF. The ability to put all of that into a pipeline is, I think, questionable. There is some stranded gas in Canada. There are nuclear facilities that would like to access urban markets but can't

get close enough to them that could also be seen as stranded energy.

Urban load pockets are the opposite. We've already talked about this. There's arbitrage. A number of major traders have expressed interest in the ability to arbitrage PJM, New York, southwest Connecticut and Boston. No matter what happens to congestion, there's obviously going to be differences in pricing dynamics that a trader would like to catch in using a system like Neptune.

Developing such a merchant project is long and difficult. Neptune began at the end of 1998. It has 100 notional risk points divided into six or seven buckets. The biggest risk was if people would bid. Now that they have, the risk is taking the bids to contract. The remaining risk is getting permit approvals from state and federal authorities. There were five initial partners and technical help. The challenge is to create the AES or Calpine paradigm for merchant transmission. When a small company does a project, however, you have to change the sequence that a large company would use. For example, you do the financing and permitting last. First, put open season test into the marketplace and see if the market will bid before committing a lot of money to permitting processes. This changes the sequence of development. The economic challenge is that all merchant transmission investment is a spread play. In a market like we have today where you have the Enron meltdown, and a significant reduction in the value of trading entities as a whole, people's ability and willingness to finance a 20-year view of a spread is

gratifying. In the finance community there is an ebb and flow of the willingness to make long-term commitments. There is much more willingness to commit to the New York-PJM legs, where there is locational marginal pricing and people can look at the pricing history, than there is in the pool. There is significant market confusion about how big the LMPs will be in the pool once it gets started, and how much money therefore you should be willing to commit to deliver power into Boston or southwest Connecticut.

On the regulatory side, we are great believers in the proper way of interconnection financing policy. The more generation interconnection costs are socialized, the less you incentivize merchant transmission. We are very much on the side that says do not load the customers down with lots of generation interconnection costs. And we're obviously tremendously influenced by how the rules evolve over the years.

Immediate issues under discussion in the three pools are: a request at FERC for a clarification on the PJM export tax, export tariff. We are asking FERC to rule that a system like ours should not be subject to an export tariff, as a company exporting across the AC system is subject to. In New York, we've begun the Article 7 process, and in New Jersey we expect to finish the permitting process there for the New Jersey to New York leg some time in 2002. In PJM, there's an issue in how to deal with a company like Neptune. Are we a customer of PJM? Do we get treated as a generator and therefore we're in the generation queue, or are

we a transmission provider? It would be advantageous to be a transmission provider instead of yet another generation project in the six queues that PJM has.

How do we deal with the challenges of the suppliers? This is a very small market in terms of the companies producing this equipment. DC Cable essentially only has three companies in it and they are capacity-constrained. One or two big orders can make a big difference in when you can get a system delivered. There is a need for more capacity. Converter stations are run essentially by Siemens and ADB, and again, there is considerable preparation time. Gen Power is an example of a company that is developing a merchant power plant in Nova Scotia with a long generator lead that is essentially a transmission cable all the way into New York. Competition is good because you get different models of how this might all shake out.

Here is a forecast of unconstrained NEPOOL reference prices. The blue line is our forecast of what will happen if both a domestic power plant and the Neptune project get built from 2002-2010, some congestion, but not much. If one or either one doesn't get built, the Boston congestion premium will get higher because it needs additional power in the post-2006 period. The purple line would be the effect of neither Mystic nor Neptune being built. The desired outcome is as Jim Lyles says, "Might there be a speculative bubble in transmission."

#### **Speaker Four**

I'll give you an explanation of the scope of the Midwest ISO and the market. Currently there are 19 transmission-only members and 34 non-transmission only members. There are more than 100 employees in the control center in Carmel, Indiana. The transcos Translink and the Detroit ITC have filed to join the Midwest ISO. FERC has no rule yet on these transcos and we are expecting guidance as to ISO transco coordination. The territory is now 18,000 MW peak load and 89,000 miles of transmission. The utilities in the Midwest serve 15 states and Manitoba. We are in the middle of completing the marriage with SPP that will expand the scope of the ISO to 20 states plus Manitoba. We will continue with our headquarters in Carmel and have another control center in St. Paul, Minnesota. This is part of the ongoing merger with MAPP. We will keep the SPP control center in Little Rock.

With SPP, we are going to go to 100,000-120,000 MW of generation capacity in the ISO. The target for completion of the merger is early 2002. The combined utilities will serve 12 million customers and have 141,000 transmission line miles.

We are proposing that the entire region is a single market and should be treated as such. Because of the scope and magnitude of this market, the Midwest ISO is proceeding carefully, making sure that the design has a lot of flexibility and its details are developed in conjunction with the stakeholders. Some of the issues are real-time operation and pricing, day-ahead market, transmission rights, resource

adequacy, inter-RTO coordination and market power. As you know, the Midwest ISO is on target to go into operation December 15. The market design I am talking about is targeted for early 2003 and will not be included in the initial operation of the Midwest ISO. Congestion imbalance is going to be dealt with in a different way – what we call the Day One operation. However, I am going to focus on what we call the long-term date to market design.

As background, a congestion-management working group was established in October 2001 with the charter of designing a new market-based system for managing transmission and energy imbalance that will be compliant with the FERC order and meet the stakeholder needs. This design work was divided into two phases: high-level design and market rules, or the detailed design for implementation. The high-level design has been completed. We just had an approval vote from the stakeholders to go ahead with the detailed design. This is a stakeholder process and everyone was represented in the working group, including regulators, transmission owners, power marketers, independent power producers and customers. It has been an open process and we have had the benefit of hearing different points of view and perspectives.

To move ahead requires systematic planning and discussion of the issues. We had to be ahead of the group to guide the discussion. The vote took place on November 28 and the straw proposal, an 80-page document, was approved. This public document has the fundamentals of the design listed:

constrained dispatch in real-time, location and marginal pricing for imbalance and congestion. Transmission rights are based on point-to-point and flowgate rights. There is a real-time spot market and a day-ahead spot market. It is hybrid, rather than an LMP because it contains the flowgate rights that are not included in the PJM model. This is a multi-control area type of setup; we are not requiring the individual control areas to consolidate or merge into a single control area.

Another feature is that it calls for a stage implementation. Not everything goes online on Day Two. The market for regulation has been deferred until Day Three, which is basically one year after Day Two operation. It's worthwhile to note that the Alliance RTO has not had the opportunity to really discuss and either accept or reject the proposal. At this point, this is the Midwest ISO proposal and concept.

I will now discuss the real-time operation, or the real-time spot market. What we propose is a centralized dispatch to solve congestion and imbalance and balance the system simultaneously with dispatch intervals between 5-6 minutes. We had started with a long time interval for dispatch, and little by little, reduced it to divide more clearly the functions between the ISO and the individual control areas. MISO will send specific generator signals through a control area directly to the generators. Market participants can submit bilateral (unintelligible) schedule and so bid into a real-time market.



On the initial operation of the congestion management systems, the individual control areas will be responsible for regulation. That is different from PJM and the northeast. On Day Three, we will move towards a single regulation market. On Day Two, we are going to work with the existing reserve sharing agreement. In the case of the Midwest ISO we are dealing with reserve sharing agreements and that are legally binding agreements that we cannot just dissolve or modify.

In early 2003, we will have to accommodate these existing agreements. The ISO will have responsibility for making sure that we reserve enough transmission in the system so that the reserve can deploy and we will be able to activate those reserve sharing agreements when needed.

On Day Three, we move toward a single MISO-wide reserve sharing pool. One of the main concerns from the ISO standpoint is resource adequacy. The Midwest has never been dispatched as a single region in a centralized way and that's what's going to happen. Another concern was that the ISO was taking the responsibility to meet the load every 5-6 minutes. We wanted to make sure that there is enough generation in the system for us to do our job. This was a big point of discussion during our design process. The day-ahead market is also part of our design, very much like the PJM model. We plan to get the transmission schedules and the market participant will identify capacity for relation reserves and the capacity for meeting the load.

A few differences with respect to the PJM model have to do with point-to-point and flowgate rights. This has a lot of history in the Midwest. When we started, there was discussion about flowgates and financial transmission rights. A compromise was the hybrid model that includes both, and in our case, these transmission rights are financial. We call them PTPs rather than FTRs because FTRs have been defined only as obligations in the case of PJM and the northeast. In the Midwest, they can be options. Long-term transmission rights will be made available, a request from the market participants. The PTP is pretty close to what PJM has already implemented. It will hedge all the constraints, settle the day-ahead prices. You can always schedule in the day-ahead market.

Flowgate rights can be obligations or options. They hedge only a specified flowgate as specified basically constrained in the system. They don't hedge all the constraints, but this is an individual type of limit. They can be PTDF or OTDF flowgates. PTDF is a flowgate that has basically one critical element, while an OTDF has a contingency associated with the critical element. This follows closely the model using the Interchange Distribution Calculator, or IDC, very familiar to the Midwest. We don't guarantee shift factors when we model flowgates. They are set at real time a day ahead in the day ahead market. These are the main characteristics of the flowgate rights, done to avoid uplifting, which was an issue for Midwest transmission owners who wanted to minimize uplift as much as they could.

Our initial approach to distribution of the transmission rights is to have the allocation at the beginning of Day Two. There will be a transition towards an auction of transmission rights, similar to PJM. We are not going to require grandfather rights to convert; they can continue as they are until the expiration of those contracts, or they can convert if they want.

Regarding long-term resource adequacy, stakeholders expressed a clear concern about ICAP markets in the northeast. For now, we will assume that there will be no bid or price cuts and that, therefore, will be the mechanism to address the long-term capacity.

Why are we proposing a single market in the Midwest? Basically, we want a single set of real-time LMP prices for the entire region. There should be a set of comprehensive financial rights through the combined region. And the market participants will have a consistent set of rules for trading and scheduling resources. It enables efficient use of resources, integration and transmission, and it leads to significant savings in infrastructure, since the Midwest doesn't have this type of system. Those are the benefits of a single market.

## **Discussion**

*Question:* Is there any level of congestion that would constitute an efficient outcome? Don't transmission owners and energy service providers, demand-side management providers, energy service companies profit from congestion, whether it's through a

PBR, a shared savings approach of congestion, or more directly, through the addition of regulated investment that eliminates congestion?

*Response:* To the extent that the cost of congestion is less than the cost that would be incurred to relieve the congestion, then that level of congestion is consistent with an inefficiently functioning marketplace. When the costs of congestion exceed the cost of the remedies that could be taken to alleviate it, congestion becomes uneconomic and inconsistent with the function of an efficient marketplace.

A company doesn't necessarily profit from congestion on the system as it operates today. With regard to investment in the system on a going-forward basis, yes, because that's how rates are designed. I don't know what the ITC's rate design will be. If the rate design has some component where there is a regulated return tied to investment and capital, then the ITC would profit by making the investment in the system. I've suggested that if the market is willing to step forward and invest in relieving congestion, there really is no reason for the ITC to implement a solution that's become unnecessary or duplicative. But if the market doesn't step forward and there is still uneconomic congestion, there are two choices: trust that the market will respond at some point in the future, or the regulated company makes an investment that would reduce congestion costs to consumers. The latter is a legitimate public interest role, or backstop role, that regulators should look for the regulated entity to provide.

*Response:* What rubs me a little bit the wrong way is the implication that only generators and merchant transmission providers profit from congestion. I believe a regulated transmission owner can also capitalize on congestion through regulated transmission assets that increase through the traditional rate base.

*Comment:* Distributed resources, in essence, profit from congestion. We're looking for a set of rules that send price signals to all market participants so that people who think they have a better way to relieve congestion will be given an opportunity to do so in the market, as opposed to the situation where we decide to do that on a socialized basis, and therefore never get to uncover what could be less costly and more effective solutions.

*Response:* To the extent the system is congested today, not congested tomorrow, congested the next day, does it affect profits? No. If a company invests capital over time, there is profit tied to the investment of capital over time. That is not necessarily bad. If a company can put forward a market project and can profit on that, that's fine. But a backstop role is not a bad thing; in fact, it's essential to all consumers. If the market doesn't come forward with projects to alleviate congestion, there is a legitimate public interest backstop role in having the regulated entity, much as it always has, undertake the capital. Where we differ is that under the scenario I outlined, the market has a chance to respond first. What I would argue against is turning that process into a least-cost planning process, because if the market hasn't responded, there is the

potential of tying a regulated entity up in knots so that it is unable to make the necessary investment. Everybody with a financial interest in congestion will use the process to argue that the transmission solution isn't really the lowest cost and you could do a merchant transmission project for the purpose of delaying any action and preventing any investment going forward.

*Response:* I share your concern about people who will delay the process just for personal gain. But I have a hard time accepting the assertion that there should be a regulated entity with the authority to invest in only one kind of solution, and that they should do so without engaging in a hard look at the alternatives. The backstop should include a look at alternatives, and you want to put a time frame on that to make sure that customers are not denied benefits for a long period of time. It's hard to get comfortable with the concept of least-cost planning, but what's the alternative? Planning without consideration of costs is obviously going to be the answer. I suggest that the backstop provider figures out a solution and what it will cost and puts that money on the table. For example: "We think it's a \$30 million solution and therefore \$30 million of uplift in this pool is going to be available to whoever bids to provide the best solution to this problem." The low-cost bidder against that pool of money wins and is required to deliver the solution on the same performance basis as the backstop provider would have.

*Response:* New York is worse from a congestion standpoint than the

neighboring pools that also have some congestion. I don't accuse the utilities of doing this, but there is an incentive to have congestion either stay or get worse because it bottles the cheap generation in western New York and therefore, their own power prices. If they're on fixed rates, it makes their power prices go down. A simple example of how an ITC type of arrangement can help is New York's Central East that is the most constrained interface in the nation. The T&D sections of utilities will not move an outage to a weekend or off-peak periods because that causes overtime that they get no compensation for in their budgets. If FERC or the NYPSC would agree to a shared benefits type of arrangement, if you want to call it incentive ratemaking, those things yield huge benefits for customers. Put these on the table and if the various regulators who have to deal with it actually do so, you will see congestion relief and capacity, transmission capacity improvements that will benefit consumers. After all, that's what we were supposed to be doing when we embarked on deregulation or re-regulation in the first place. Without more federal prodding, not necessarily pre-emption, I think the states are still generally operating from a transmission standpoint in the monopoly mode. The reality is that they operate under political constraints that make it very difficult to really do something.

*Question:* Does the RTO model have the ITC run the whole operation, run the spot markets as one global entity that is the English model? Or is it the New England model with the ISO performing the spot market and system

functions? It seems to me that one can implement an RTO model that has an ITC that enables the ISO to continue what the northeast ISO does. Is there some inefficiency in creating two organizations?

*Comment:* There are tradeoffs with respect to which model a region chooses.

*Comment:* One of the peculiarities of the DC entities that are being proposed is that they will relieve the Central East constraint to some degree. A solution to congestion is different types of transmission connections.

*Comment:* From my view of the world, you get clear property rights to whoever does the resolution so that he gets the benefits. Ignoring whether or not you can operate the market, if you identify that in your role, you should, but below the line, not as a rate base, not as incentive-based ratemaking. I'm troubled that that line becomes very fuzzy. Either as a merchant generator or a merchant transmission entity, I have to face the situation where you cross that line without the worry of putting it below the line. You cross that criteria without having to worry, and you can rate base it. Suddenly, I have to make an investment where it was predicated on competition, but not subsidized competition. The fuzziness is that what is non-economic and what is economic wind up with my project going bankrupt. The idea that you can identify it tells me that you ought to do it and compete with the rest of us. I find it a non sequitur that there would ever be an acknowledged uneconomic situation for congestion where we want to see rate-based entities doing

something. It undercuts all the other solutions that we've been talking about and it drives up financing, chilling the market for everybody. Almost by default it pushes more onto the ITC entity because nobody else can do a merchant facility for fear that their financing will say, "I'm sorry, this guy, whenever he wants, can step into the market and make these investments."

*Response:* I guess we fundamentally disagree. Where we differ is whether the market is going to step forward and always remedy uneconomic congestion or whether there is a role for the regulated monopoly to invest capital.

*Question:* In that environment, why aren't you willing to take the market-based return on what you have called an uneconomic congestion situation?

*Response:* The argument is that you will chill investment in the marketplace down to the hard points. How do you define the role of the ITC so that it is doing the backstop function? I would suggest that the checks against the ITC over-investing versus the risks and obstacles of just reaching the level of investment that's in the public interest is heavily rated right now on checks that make it difficult even to proceed with the level of transmission investment that's in the public interest. The one thing on which there's almost universal agreement is that there is an under-investment in transmission infrastructure. I think it would be a mistake to go to a system without the backstop obligation or that makes it difficult for the regulated entity to invest where the market has

failed because the asymmetric risk is there.

*Comment:* I wasn't suggesting that there is no backstop. We do accept there are values by any reasonable market measure that would not be deemed economic as an investment. The problem I'm having is that the line is way over here at a reliability function that nobody else is going to touch because you can't ever make a nickel, but it's vital for stability and the returns are high and if you want to do those, why don't you just do them below the line.

*Response:* It's not the appropriate role for the ITC.

*Response:* The reality is that the market is not going to fail, especially in New York, thanks largely to LMP pricing. FERC could help clarify some of the issues, but I think people recognize it will be a year at least before the NERTO rules are laid out clearly.

*Question:* I have a question about the potential merger of the 20-state region and potentially 120,000 MW in the Midwest. With so many different control areas, do you then create a potentially complex governance solution that may not work?

*Response:* One of the biggest issues is infrastructure and operations. Whether it's a hierarchical or distributed approach and whether we have the technology to run such a system is being developed. We need to be careful about not creating internal issues within the ISO. Transcos and the ISO will try to come up with

protocols to coordinate with the ISO. No one wants to balkanize the power system and there is a need for having a central coordinator, the ISO, for real-time operations, spot-market and day-ahead market. My guess is that six months from now we will have the framework.

*Question:* Using incentive regulation aids transmission owners to maximize the availability of existing facilities. What hope do you have of persuading FERC to move into meaningful incentives that would result in changed behavior? And if I were a retailer, why would I want the possibility of flowgate rights at the same time?

*Response:* Obviously, there is a problem with the economic incentives that exist under the current system. Both in Order 2000 and in the order on the New England RTO, FERC has been very encouraging with regard to moving forward on incentive rates. We filed a proposal with FERC to take a line out of service for maintenance in the fall, rather than in the summer, to reduce congestion. Over 90% of NEPOOL voted for this innovative practice, but FERC rejected it. So we get mixed messages.

*Comment:* Do you want to create an incentive structure like the UK model to cost-effectively reduce congestion? The incentives ought to be created for a system in which the lowest cost, most efficient, most reliable solutions are the ones that people get incentives to do.

*Comment:* Many have asked why flowgate rights are needed, if we are going to implement point-to-point

rights. The short answer is flexibility. One reason why flowgates are attractive is that they clearly identify the binding constraint. In a region as big as the Midwest, there are many combinations of point-to-point rights and if you only have a few flowgates that will allow you to transact better. For example, the Eau Claire 345 KV line that links MAPP with MAIN between Minnesota and Wisconsin has been the top flowgate in the last 3-4 years and could stop as many as 200 transactions control area to control area. By obtaining a flowgate right on that line, it would allow you to transact all the way down to SPP and TVA. Provide that flexibility in the congestion management system and let the market decide which is the preferred hedging mechanism as we move into operation.

*Comment:* Supporting the notion of ITCs and the principles of open architecture are important, and making sure that transmission owners get the right incentives to do maintenance when it's needed, not when it's convenient for budgets. Some of what I've heard is that the ISO or the RTO should do most of what is done today. We're back to the debate about how to separate markets from transmission. We've found that efficient use of the grid really comes from efficient pricing and that may be one of the key differences between the UK and even New England at this point that doesn't have location and marginal pricing. PJM/New York is making pricing drive the efficient use of the grid. And the market operator really does have a vested interest in the outcome. But these things together lend uncertainty to the marketplace and have the

potential to undermine the competitive robust nature of what we're starting to see in the northeast and elsewhere. As a transmission owner, if my business is asset management of the transmission asset and that's where I'm going to make my money, why do I want to do administrative and not-for-profit functions that take me away from focusing on my core business of asset management? That's really what an ITC is about. Through FTRs that really financially represent the transfer capability of a system there might be a performance mechanism that says when people need the system, it becomes congested. If the transmission owners are doing a good job, they should be able to keep some of the benefits of managing congestion and making that transfer capability available. If they aren't doing prudent asset management and they're eroding where the system can handle the transactions needed by the marketplace, then maybe they have to pay back some money. Would you want these distractions? Do you think this sort of performance-based mechanism might fit into where your thinking is on ITCs?

*Response:* The reason the ITC should do the basic core functions of transmission planning, expansion, designing the rate tariffs and filing them with FERC is that a for-profit company will be able to have the right financial incentives to produce benefits to consumers that aren't being produced today. The way you produce those benefits is by putting in place a rate structure where the transmission provider (the ITC in this case) on a regional basis, has a rate structure that enables it to share in the benefits that it

creates for consumers. Today, we don't have the right financial incentives in place, so it's both a business opportunity and an opportunity that aligns with FERC's policy objectives. We agree that creating financial incentives for transmission providers to do the right thing is good. I see a real distinction between congestion pricing and management. LMP as it exists in PJM and in New York and as it will be implemented in New England properly prices congestion on the system and gives incentives to market participants to respond. But that is very different from managing that is having the transmission provider take actions that will further reduce congestion. The things that transmission providers can do, even if you price them correctly are moving outages, such as taking the type of action of working the line live. To me managing congestion is coordinating outages in the region, a positive, proactive thing that can be taken over and above the price signals that are given. It could be done by the ISO or by the for-profit ITC. If someone has a financial interest in making these results happen, are they likely to be more aggressive in identifying and implementing them? I suggest that the answer is yes because financial incentives matter, and people take actions based on the financial incentives they're given.

*Comment:* When you say we price everything with LMP and then market participants respond to manage the congestion and we now have the for-profit ITC also responding to manage congestion, that is where uncertainty starts because everybody is competing to do the same thing. Maybe some

market participants can't control market outcomes. Maybe in some models one can.

*Response:* I was suggesting that the actions that ITC takes were short-term, whereas the market response is likely to be longer term, building the generating plant, developing the distributed generation, building the merchant transmission line. With long-term there is tension between the market participant taking actions and the backstop function. There are numerous checks that can be designed into any system to avoid the ITC stepping out of its backstop role. One is that if you have a hybrid system, have the ISO review the plan and certify it as being good. Beyond that, the ITC is always going to be subject to prudence reviews. If it builds something that is subject to challenging at FERC, the ITC has the prudence exposure at FERC that its costs will be disallowed. That's also a check on the ITC building unnecessarily. And you've got siting reviews in the states. I suggest that the best check is where you design rates so that the ITC's financial incentive is derived not just from investing in capital, but from a rate structure that rewards it from reducing congestion in the lowest-cost way, whether that is operating practices or capital. Let the ITC make those decisions: if it can reduce that to operating practices, it would be a good result. But no, not get into the generation business.

*Comment:* Going back to the discussion on distributed generation and demand response, I agree that there has to be demand response built into the system and enhanced to really

get our markets working right. But two things have tied us up in knots: the great difference between a retail price response, and load management and distributed generation, which requires some sort of active intervention. The fact is that the load-serving entities in PJM have no incentive to push that kind of active intervention unless they can make money from it and they have a very significant financial reason to oppose it if they're going to lose money as a result. On the issue of should you compensate the LSE for the loss of sales, what do you do about LSEs that are built on the basis of profiles? If it's not the load manager, should the LSE somehow gain compensation for having someone else trigger these load management events? On the issue of jurisdiction, there is massive confusion about who's in charge here. Is a load reduction a wholesale or retail matter? Is it FERC or the state?

*Response:* First, we definitely have to harmonize the incentives that are given to wholesale providers and to retail load-serving entities and wireless companies. The New England Demand Initiative is an attempt to come up with the best slices through the disharmonies into a coordinated answer.

*Question:* When is MISO's Day Two? How will companies be operating until that time and until there's a FERC-approved market monitor and mitigation scheme? What kind of market rates authority will they have?

*Response:* The target for Day Two operation is early 2003. Before that, we are going to have what we call a



Day One congestion management system, basically an electronic bulletin board for generators and load to post bids. That's the way that we are going to support a bilateral market and that the ISO will select generators in order to perform reliability re-dispatch. Regarding market power, in the Midwest ISO there are several load pockets present because of market power concerns. In that regard MISO has an independent market monitor that will be in operation on Day One. For Day Two we will have mitigation schemes along with market design; we need to do work in understanding what kind of market power issues are customers are concerned about.

*Comment:* I want to clarify the ITC in the Midwest. Can it be a singular entity with a footprint that's

contiguous with the RTO footprint, in which case it may have certain implications as to appropriate functionality? Is there room in the model for multiple ITCs simply being an unbundled ownership of the transmission asset from a corporate structure standpoint?

*Response:* I was implying an ITC that has the same geographical scope as the RTO. To the extent that's not true that you have more than one ITC within the geographic region, it does affect how you would allocate functions between the ITC and the ISO or IMA, whatever you're calling the other entity. Whether the northeast comes out as one ITC or less will be determined by discussion among the parties. There is potential for one or multiple ITCs.

## Session Two: Standard Retail Market Design

*The results in retail markets opened to competition have, in the eyes of many observers, been less than inspiring. Few customers have switched, or are migrating back to the supplier of last resort. Nonetheless, the market is young. New models are coming on line in such large states as Ohio, Texas, and Illinois. Moreover, while the number of customers who have switched is lower than hoped, the percent of load that has switched is larger. Where then do we stand on retail competition? There is consensus that viable retail competition requires a strong wholesale market, but there is not a clear consensus on the converse. Is retail competition necessary for the wholesale market? One lesson that California taught is that wholesale price signals cannot be disconnected from price signals. How can that link best be made? Can the RTO, as in Texas, enhance retail competition? What incentives, if any, are needed to motivate consumers to explore their options? Should incumbents be required or provide incentives, as in Ohio, to lose load? If retail access is functional only for large companies, can access arbitrarily be cut off at a specified level of use? How do we make retail and wholesale market designs and regulations consistent and reinforcing?*

### Speaker One

I will cover three things: the current condition of our restructuring, as I prefer to call it in contrast to deregulation, in Ohio; the unintended consequences of unbundling, and looking forward to the end of the market development period. We are eleven months into it and without qualification, haven't done that great. In terms of load shifting, the first energy companies have done the best; northern Ohio has done significantly better than central or southern Ohio and there are a couple of reasons. The prices were always higher in northern Ohio. Second, as we embarked upon our transition plans, First Energy came out with a program to move the legislative mandate which was to move 20% of the load of each customer class during this transition period. Its Market Support Generation (MSG) set aside nearly 20% of their generation

for marketers at 25% discount that immediately gave aggregators the ability to latch onto a certain amount of generation. MSG did have the effect of getting people to realize that there were other sources of supply than for the First Energy companies. There has been a lot of municipal aggregation and some other suppliers have latched onto the market support generation supplied by First Energy.

With the other companies that also have the mandate to move 20% of the load, our rules were so vast that we had to write to go along with the legislation. However, other companies haven't had a lot of success. There's been an enormous amount of advertising: \$17 million the first year statewide and another \$16 million over the next couple of years to advertise choice. I'm not sure what it is. The shopping credits are there. Every bill has a price to compare, the Web pages

are all full of prices, apples-to-apples charts, what have you, to buy, but it doesn't happen. Cincinnati Gas & Electric actually has a shopping credit that exceeds their generation rate; their load shift has been 1.8% and that's almost all commercial-industrial.

I suppose what's happened in California makes people nervous. Nevertheless, it doesn't seem like the problems we do have in the wholesale market have clearly manifested themselves yet, because prices are fairly low and there should be enough headroom. What about the 20% mandate? We've got to get 20% of the load shifted over the next four years and there's only four years left. Actually, for Dayton, there are two-and-a-half years. I think the short answer is nothing. If we can't do it, we can't do it, when you're offering shopping credits that exceed the generation rate.

One of the more interesting aspects of the market support generation that was set aside by First Energy was the protocol they set up. You had to have your customer base in place, you had to apply and you had to do certain things. Cleveland, Parma and Toledo are some of the significant municipalities that got on board. But it turned out to be a quagmire and it was brought to the PUC that should have said that the protocol was set up by First Energy with respect to whoever wanted the energy. By not staying out of it, an unintended, significant consequence has been the use of the PUC's resources. With respect to unbundling, we knew what the transmission and distribution rates

were. The generation component turned out to be a residual. For the duration of the market development period, rates were frozen. When you do that in certain areas, you lose the subsidy that came from generation because even though it's free, there's still a frozen rate to the end-user. One of the biggest issues that arose was that of line extension policies. Who ever thought about that? The companies decided to start charging the incremental costs of whatever it was to homebuilders, developers, commercial and industrial users. Builders have a lot of political contacts. The PUC managed to get the Homebuilders of Central Ohio and AEP to reach a settlement. It opened an investigation that froze the price at the preexisting rate so people wouldn't get hammered when they built their buildings and the rates that will go into effect for line extensions will be retroactive to the date at which we signed the order. Then the builders would come in and say, "You're charging us \$1,000 a lot. That's going to have a profound impact on our ability to sell homes." The line extension issue is big because it was a big political issue.

Pole attachments became a big issue. For \$400 a year per pole, the cable companies were able to use the poles of the electric companies. With more digitizing, broadband, the utilities then said that because the tariff says they have the right to determine whether harm will be caused to their poles, they would hire a third party to evaluate each pole for strengthening. Unbundling kind of aggravated everything. I think the companies see the revenue possibilities and at the

same time they probably deserve it. Every other week it seems like something new comes up as a result of restructuring. It's probably not so much a problem because of unbundling as much as it is the frozen distribution rate. Since the legislature won't take another look, we have four more years of dealing with these types of issues. In conjunction with that, we need to start looking to the end of the market development period. We're going to have to make a choice. Are we going to focus on what's food for the market in terms of wholesale transactions, or do we really care about retail? Who's going to be the provider of last resort?

There's a couple of ways that can work. Obviously customers who switch are going to migrate back to the electric distribution utility, or EDU, usually during the summer. Right now, we have what's going to be called a come and go rate. If people really want to come back, and if they don't want to stay for a certain period of time, then they'll have to pay a price. How do you do this if your rates are frozen? We think we can with a new rate that never existed before, so it's a new price. If you choose to come back during the summer because the EDU is offering something a little less costly and because the EDU will absorb costs to supply you, we believe that should be reflected in the price that you pay as a migrating customer.

If the EDU is forced to be the provider of last resort, we know there's going to be a standard offer price. That's already provided for. It could be a market-based price that people who

return to the EDU will have to pay, obviously, because the company has to stand by to provide the customer with whatever they need. What does this have to do with our ability to get people to shop and move around? We're going to set up a contest between the supplier who wants to be out there supplying and the EDUs. In general, if you have a standard offer price that exceeds the market price I think it's going to elevate the price overall. Some may say that's a good thing because it creates headroom, higher prices potentially, but more competitors that might be good for retail and may mean more choice for more people.

The law provides an option to bid out those customers who would otherwise remain with the EDU. If the EDU chooses to say to an aggregator or to a supplier that it's going to bid out all the people who have not chosen to switch, they become just another player if they choose through an affiliate to become involved in the bidding. But when that happens, we begin to turn more toward the wholesale side of the market and we have the EDU competing for power just as we do the other suppliers. We have potentially lower prices and if it's an opt-in type of bid, the prices can be even better.

We don't know exactly how it's going to work, but we feel the need to address the wholesale side versus the retail side. There's not a lot we can do on the wholesale side, particularly now that we're all a little bit chagrined by the collapse of a major player, but if we don't have a good wholesale

market, we're not going to have a good retail market. We've heard that time and again, but we can adjust. If we don't have a good wholesale market, it'll be due to the conflicts we're always hearing about inherent in the transmission debate. Obviously, the ability to site peaking plants or combined cycle plants or even coal, which is a possibility, closer to the load gives us the ability to cover our flanks. We don't want to be caught short and the closer to the load, the better off we're going to be. Despite what the contract price is, when we're close to the load, we know we're going to be better off.

We can aggressively pursue demand-side management which I think needs to make a comeback. We need to push for an enhanced wholesale market; in the absence of that, we'll do whatever we need to as far as alternatives are concerned to make sure that the lights will go on. With a good wholesale market, we'll have a better retail market. Generation would be placed much more efficiently and in the final analysis, end-users will be better off if we focus more on the wholesale side.

### **Speaker Two**

My objective is to build a framework by restating some rather familiar observations and then examining the current threats they pose to retail markets. We have seen two definitions of what constitutes constructive competition at war since the debate over restructuring began. Essentially, the form of competition that we have seen is a definition of the word,

competition. The objectives of the two parties are quite different: one party is trying to clarify ideas and bring existing theory and knowledge to bear on defining the topic, and the second is trying to persuade the power-makers and the legislators to accept their view.

All parties accept the proposition that competition is not desirable in and of itself; it's just an instrument to get you to someplace else. Economists and regulators who tend to draw their definitions out of the written literature of scholars define that something else as being economic efficiency. In contrast, the parties who define competition in a different way and draw heavily on the business literature see competition producing rapid economic growth. That's a very hard proposition to test, but in a sense, the language is different. As a result of the language and the conflicts that it manifests, the gridlock in Congress over restructuring is aggravated. As a result of the definitions we have inherited from the professional literature of scholars primarily, economists and regulators have developed a predisposition or bias in favor of what constitutes an efficient market. Essentially, they want the firms to be producing highly substitutable commodities, perhaps even with the same commodity, and exchanging those commodities within a well-structured network. I can draw the distinction this way: there is a tendency for those advocating efficiency in the economic sense to think in terms of the fact that government creates a structure for the markets and the firm chooses to participate or not, accepting the rules

of the market. The definition of competition in the business literature rejects that model in effect, if not explicitly; its model is the business of redefining markets, abolishing old markets, creating new ones that better meet your needs and defining the rules for those markets to benefit yourself and your firm.

Consequently, economists and regulators following this model have this bias toward commoditization. They tend to think of the desirability of creating and efficiently trading the commodity. The poolco advocates illustrate this point well. Practitioners, in contrast, tend to resist the idea of commoditization. They are producing a service that is unique to their firm and to commoditize that service defeats their purpose. They argue that they are facilitating and increasing economic growth over what it would be otherwise. A quote from the business literature illustrates this dilemma: "A large portion of the strategic planning budgets of the world's largest and most sophisticated business is spent on figuring out how to turn around businesses that are being commoditized." The last thing you want if you are running a dynamic, big firm that's going to grow rapidly is to let your product be commoditized.

The second view is that the goal is not to win at somebody else's game, but to change the game to one that you can win in. You don't go into a competitive market and play that game; you play a different game where you have a definite comparative advantage and you can win.

These two rather substantial conflicting views have been brought to bear in the political debate. I can summarize by saying that while many have been trying to clarify and support an efficient market as economists define efficient, other parties have already been competing for ten years now in the game that they want to play, which is defining the markets to suit themselves. A part of the game that they've been playing required the creation of gridlock in Congress so it would not freeze anything in place until after they had established the rules, framework and institutions that they wanted to perpetuate. In short, it starts with the recognition that Congress, and all political bodies and all regulators, have great respect for the preservation of rights in the status quo. Regulators and legislators have a tendency to define fairness as: "Thou shalt not deprive me of my beneficial interest in the status quo."

If you were a large electric utility in the early 90s, you could see deregulation and restructuring coming. Congress enacted the Energy Policy Act in 1992. If they enact legislation a few years after that, you're going to be stuck with your old structure. You want to create a new structure so that when Congress does get around to acting, it will preserve, or help you preserve, the new structure you've created. Part of the problem was how to keep Congress from acting, which turns out not to be too difficult. Watching the gridlock in 1983 as Congress restructured the natural gas industry, it's not difficult for large

firms in the electric industry to create gridlock.

Part of their success came from the lessons of the 80s, because when Congress went into gridlock, FERC gained enhanced power. You'll notice that FERC has been in gridlock for about four years. I think now they have the votes and can move forward and we will see if we solidify the new status quo.

I want to say a word about the problem of dealing with the states. We did not empower a federal agency to create efficient markets. We left it to the states and we now have a particularly difficult problem. Many years ago, we had the Alcoa case, an important antitrust case, come before the Supreme Court. Judge Hand and his fellow judges came to the conclusion that the existence of monopoly power and its exercise were indistinguishable. Therefore, if you prove the existence of monopoly power, you have proved the violation of the antitrust laws. However, history shows that the Supreme Court never endorsed Hand's decision and now we live in a world where, in effect, the possession of monopoly power and its exercise do not offend the antitrust laws. It is only the abuse of monopoly power that offends. We have a concept of the law which is a little like pornography: somebody's supposed to know it when they see it, but there are no particular standards of what constitutes abuse, as far as I can tell, although I presume they will slowly evolve.

If you ask what the justification is for restructuring the electric utility

industry, we were given these comparisons, or we created them ourselves, between the operations of an efficient competitive market and the operation of a regulated monopoly. But if the possession of a monopoly is not illegal, and we now have FERC (at least in the form of Judge Wagner) issuing an order in the California case that the exercise of monopoly power by generators is not illegal if it's not abused, then our justification which depends on the absence of monopoly power rather than on unexercised monopoly power, fades away. In short, it becomes logical behavior for every generating firm that is deregulated today to possess as much monopoly power as it can, and it is not illegal to possess it, as long as you don't abuse it. But can you exercise it without abusing it? Hand said no; the Supreme Court said yes. We're stuck in that today with much of our justification for moving to a competitive market having been eroded by the changing standards of antitrust laws. Consequently, we see a fear of competition and an inability to create the circumstances based on competitive economic theory that would prevent the states from dragging their feet. Interpretations of the antitrust laws are reinforcing that.

In California, why were some of our forecasts wrong? For example, many supporters of California restructuring were environmentalists who wanted to get the stuff out of state. They expected to see the generators built in surrounding states and Mexico. Why weren't they built? If you're the governor of a state that is able to sell all its surplus power into California,

your regulatory commission is smart enough to require the generators to share their profits with local ratepayers. Anybody who builds a generating plant in Arizona or Nevada is going to cause local rates to go up. So you build vested interest all through this system. I conclude that our current interpretations of antitrust law, the implications of Judge Wagner's decisions and FERC will go a long way to subverting the legitimacy of our restructuring effort and will complicate it terribly.

### **Speaker Three**

I will give a nuts and bolts description of the retail competition initiative in Texas: how customers make choices; some of the pricing indications seen; and an evaluation of customer participation in the retail pilot program, which we went to in summer 2001. Texas starts retail competition in January 2002. There are questions all the time about the problems that have cropped up in other markets. We explain that Texas has a pretty favorable supply and demand situation. I don't think that was by accident. That was something that was promoted by the way we initiated our wholesale market opening in 1995. Last summer's peak demand in ERCOT was 55,500 MW and total generation capacity 71,000 MW. The projection is that we will continue to have that level of margin over the next two years. Our legislators studied other models and decided that we would not force utilities to divest all of their generation. There are capacity auctions for 15 percent of utilities' generation

to get the market going, but there was an effort made to strike a balance with respect to generation. We also permit the use of long-term contracts to shield consumers from price volatility.

Our grid is such that we have already seen in the pilot program that we're going to face a continuing series of challenges. Bottom line, we made a change to a single control area without threatening reliability in any way. We have tried to promote investment by making our siting process as efficient as we can. Hopefully, as we commoditize the market, we will lower prices for consumers, but it is also an important development tool.

Since 1995, we have 39 generating plants that have come on line, representing about 13,000 MW. Another 20 projects totaling 14,000 MW are in development. Twenty-nine plants totaling 17,000 MW have been announced. We have experienced a difference in the pace of the retail opening in our state. ERCOT is where we expect to move into full competition in early 2002. However, the SPP region in the Panhandle part of Texas was legislatively mandated to stop the move into retail competition. In east Texas, RPC voted to delay competition because the necessary systems and processes were not in place at a wholesale level to permit the changeover to competition.

We structured the market so that ERCOT that is the ISO basically acts as a transaction clearinghouse. We thought it was important to put a neutral party between the retail providers and the transmission and



distribution providers to avoid some of the disputes that have been seen in other places. Market participant registration, training and testing and the design and enforcement of market operating rules with one exception, are through ERCOT. Texas is the only state I'm aware of in which the PUC is tasked with market monitoring. ERCOT is also tasked with designing the technical interface and data exchange standards, maintaining load profiling and metering materials and doing customer registration for the entire state.

In the pilot program, we've had a huge amount of commercial and industrial interest. We are at or close to 100 percent participation, meaning 5 percent, which was the limitation. On the residential side, most of the switching activity has been in the Dallas and Houston areas, as might have been expected. Over 96,000 residential customers have enrolled. One of the other features is that munis and coops have the ability to opt in. Many rural parts of the state are not currently participating. We feel that the pilot has been a good exercise and we've run through different issues with respect to customer switching and transfer of customer metering data.

We have played a very active role in trying to educate the market and have provided pricing information to customers in each of the regions. We've established a price to beat for the affiliated retail electric provider that is essentially 6 percent less than the base rate for 1999 when the statute was approved, plus a fuel adjustment. The effort has been to strike a balance

between bringing savings to consumers and creating a market in which there is sufficient headroom for competition to take root. We have a system benefit fund that was set up by the legislature at 65 cents per megawatt hour, which is basically used for low-income assistance and customer education programs. It funds our effort at the PUC and school funding losses due to reduction in assessed land and property value.

We're trying to eliminate confusion by standardizing billing. We encourage a bundled bill, but we do permit an unbundled one. To the extent that it's unbundled, we have the various categories set out. Our Power to Choose website provides information to consumers interested in making a switch. This is going to be an ongoing need in terms of making sure that we not only monitor the residential sector but try to do everything we can to make sure that competition flourishes, in addition to the commercial and industrial sectors.

#### **Speaker Four**

When I was growing up, my mother always told me that whenever I went into a store to buy something, not to buy it, or if I had already, to return it because she could get it for me wholesale. That's my theme and I'm probably in a distinct minority on the retail versus wholesale question. I'll begin with the typical arguments for retail competition or customer choice and then give you my perspective. The first argument, of course, has always been that customers want choice and

we need to give it to them. The second is that for efficient or true competition to occur, you not only need multiple sellers, but you need a lot of buyers out there and the only way is to move to customer choice. The third argument is that retailers provide value-added services, and that all kinds of new and innovative services will result from customer choice. Finally, under the old regulated system, it was customers who assumed the risk of utilities building plants that were put into rate base for 30-40 years. By moving to retail access, you basically move the risks away from the customers and toward the generators.

Customers want choice: I think it was probably true five years ago. But if you look at almost all of the surveys that are being done today, the only customers who really seem to want choice are large industrial and commercial customers. Given the experience in California and elsewhere, I think customers are very leery of choice, particularly the small residential and commercial customers.

In the southeastern U.S., retail choice is an academic question that isn't going to happen. Georgia had an absolutely horrid experience with retail gas deregulation, for lots of different reasons. It's on the front page of the newspaper almost every day. There are about 10,000 customers in Atlanta who have been cut off from gas service as a result of some of the problems in retail gas deregulation. When the legislature reconvenes in January 2002, there are going to be dozens of proposals to re-regulate natural gas.

Competition requires multiple sellers and buyers: I think you have to differentiate between existing and new generation. Existing generation is already located. It probably is true that in order to have efficient competition you need to have lots of buyers, but in areas where existing generation is in rate base and under regulation and there isn't much retail competition, it probably doesn't matter so much. But new generation has a choice of where it can locate and there are multiple wholesale buyers because it can locate wherever that power is needed. In addition, in most areas of the country, there are a large number of wholesale buyers. In the most recent solicitation that Georgia Power and Alabama Power did jointly, 30,000 MW of bids were received for a 3,100 MW solicitation. If that isn't competition, I'm not sure what is.

Retailers provide value-added services: I think that moving electricity towards a commodity is moving away from the idea of value-added services. In a commodity, most of the value-added services one thinks about are really financial, and can be provided with or without choice. There's nothing to prevent me from going to somebody who's willing to offer me the service and basically offer a fixed-price long-term contract and I just tell Georgia Power to send my monthly bill to them. Enron, Reliant and others have been doing just that, particularly with commercial and industrial customers. The portfolio approach as adopted in Oregon where you have the monopoly utility essentially providing different services at different prices doesn't need customer choice or retail access.

I think metering and billing are the areas most often mentioned for innovation and new services. The fact is that generally they can be provided more cheaply by a single supplier. Southern Company, a monopoly retail supplier with more real-time meters on its system than just about any utility in the country, except maybe Puget Energy, is now installing retail time and use meters for its customers. So innovation in metering does not require customer choice.

Shifting risk away from customers: It's true that under wholesale-only competition, customers are still at risk for any contracts or purchases made by the LDC. But if retail customers were to sign their own hedging contracts, they would be under the same risk of prices going higher or lower than those contracts. I think it's also true that most people think of wholesale-only competition as requiring life-of-plant or long-term contracts. There's no reason why you couldn't have a portfolio of spot purchases, one-year contracts, three-year contracts, seven-year contracts, etc., and thereby spread the risk. And in wholesale competition, risks are socialized, so even though the risks still stay with the customers, the risk for small customers, or the cost of hedging for small customers, is a lot lower than if the risks weren't socialized.

What are some problems with customer choice that I think have become evident? First is that transaction costs moving from wholesale to retail competition involves the development of a lot of

new systems and billing, and the costs are not insignificant and have caused a lot of retail suppliers to exit the business. The political constraints to true competition are probably one of the biggest problems. There is not a single instance in the U.S. where customers are facing the true costs of the competitive market. The only place we got close was in San Diego at the beginning of 2000 and that did not last very long. As long as there is a political necessity to either cap rates or to have a standard offer service or anything else, you're not going to get truly efficient retail competition. California's legacy has soured a lot of states towards the whole idea of retail competition. Even if you get true price signals to customers, the volatility in those prices is not going to be attractive and that's going to lead back to calls for either price caps or averaging pricing or the like. The lack of real-time metering and pricing that we've all been hearing about for years and that was to be a solution to a lot of the problems in California and elsewhere we're not doing and I think the reason is political.

Finally, there are barriers to entry in the retail market. You can't be a small player and survive. While there are a small number of suppliers, you're going to have less customer choice.

Georgia's integrated resource planning process I think provides a good framework for wholesale competition and avoids many of the problems in retail competition. Georgia's regulated utilities file an integrated resource plan with the Public Service Commission every three years. The plan contains an

electric demand and energy forecast for a twenty-year period, and the program for meeting that forecast, including an analysis of the supply and demand-side options, fuel diversity and environmental considerations.

After hearings and opportunity for intervention, the PSC approves or amends the resource plan. A company then prepares an RFP to meet that resource plan, including a description of the preferred options and timing. The RFP typically solicits 7-15 years out, but more typically, 7 years. The company is allowed to bid. Georgia Power is allowed to bid on its own procurement. Southern Power, a subsidiary of Southern Company, also may be allowed to bid on the solicitations, although there are some strict rules in place to prevent unfair self-dealing, such as a sealed bid which is handed to an independent auditor. To the extent that a company selects one of its own self-billed options, there is significant PSC review to make sure that is in fact the best option.

After receiving bids, the company ranks them and develops a short list for negotiations with bidders. A company doesn't negotiate with itself, of course, nor can it make changes to its own proposal after bids are in. But if it's able to negotiate a better deal than its proposal with one of the others, it of course, would take that proposal.

The bids are just generation cost bids that are handed over to the transmission group to determine the transmission costs associated with each bid. In that way, the winning bid

is really the overall sum of generation plus transmission costs. The PSC then must certify the winning bid, and in doing so it determines that the company has selected the best resource for the need that's been defined. If a company selects or decides to do a demand side option, the PSC also has to certify that program. Once certified, the company has assurance of cost recovery. Once that plant goes into service, we're allowed to recover those costs, and the PSC has also provided for an additional sum that is more or less an incentive to purchase power, as opposed to building one's own.

The advantage of the IRP process, particularly from the regulator's perspective, is that it assures adequate supplies. We build or procure capacity to meet our 15 percent reserve margin or whatever margin the PSC deems is necessary. The competitive bidding for those resource needs provides the lowest cost options for consumers, and there is flexibility on the mix of contracts, length and also whether we meet our future needs 100 percent with contracts, or whether we meet it with some mix of contracts and spot purchases. Signing seven-year or even shorter contracts provides some flexibility to renegotiate at the end of the contracts, based on current market conditions. We're not locking in prices for the life of the plant.

The process allows fuel diversity and environmental impacts to be taken into account explicitly. PSC oversight helps ensure fairness and the utility's ability to bid increases competitive options for customers. The process isn't perfect. It takes 6-9 months to go

through review. It does reduce flexibility, although there are some exceptions allowed. If there is a particularly good opportunity to purchase power on a short- or long-term basis outside of the IRP process, a company has the ability to sign those contracts and receive permission from the PSC in between these three-year reviews. And it's dependent on good forecasting. The amount of risk that customers bear is really dependent, more than anything else, on how well the utility forecasts its needs.

I want to talk about the more or less the ideal framework for wholesale competition. First, to get rid of the problem of existing versus new generating plants, the utility should place all of its existing generation in an affiliate company with firewalls; possibly divest that generation later on, although I very much doubt that state commissions are going to let utilities divest generation up front. We would put that generation in affiliated companies and have transition contracts between those affiliated companies and retail load for the time period that we still have an obligation to serve that retail load.

The transition contracts might be 3-6 years, and after they end, essentially all generation would be competitive for serving load in the wholesale market. The LDCs after that transition period, would go out for bid for 100 percent of their needs, as opposed to just their incremental needs.

We think the market should be primarily bilateral, but that doesn't necessarily mean 30-year contracts.

There ought to be some spot purchases as well and utilities should be required to seek supply and demand-side bids for needs as well. Generation affiliates should be allowed to bid, subject to the safeguards mentioned earlier. Regulators should have the ability to certify results and the certification should allow for cost recovery. LDCs should be allowed some return on purchased power as an incentive. Any subsidies in the bidding process ought to be explicit. One issue that state commissions need to consider is whether the LDC should be held out as a supplier of last resort, if for any reason the competitive market doesn't bring forth sufficient bids to meet the resource needs.

My next point is probably the most controversial, but I think that generators not winning bids, in other words, speculative or merchant plants, should still be allowed to build and be allowed to operate. But any costs imposed on the system should not be socialized. If they're not serving the needs of regulated or retail loads, they should not be allowed to socialize those costs to retail load as the winning bidders might. And finally, opportunity sales should be allowed for winning bidders.

I'll close by talking about some of the other advantages of wholesale competition. First, FERC still hasn't gotten transmission pricing right, and it's probably going to be a long time that they do. But through this IRP process, we have the opportunity to take into account real transmission cost, as opposed to postage stamp prices, or any other kind of prices that

distort the market. Market power is mitigated over time simply because more competitive generation is going to be built in response to the competitive bidding. The transition contracts also help ameliorate the market power problem because as long as those are cost-based contracts, there really is no market power associated with them.

The reserve margins are explicit, with the LDCs responsible for meeting them. So the controversial issues with respect to ICAP are avoided. Another important point is that there is nothing inconsistent with this wholesale competition model with LMP and the whole PJM-New York model. There's nothing in the wholesale model that precludes one from moving to retail competition down the road. In fact, you might start by allowing the largest customers to compete as though they were wholesale customers, and then move down to smaller customers through time.

## **Discussion**

*Comment:* There is a lot more flexibility and variety in terms of how contracts are purchased and the length of time beyond 7 years is definitely effective. There are short- and long-term purchases from buying ICAP for a month, for a day, up to 10 years for energy and capacity, etc. My comment is that there is a lot more flexibility than you alluded to in terms of the length of term for purchase power contracts in relationship with generators.

*Comment:* It's not necessarily true that there could be a lot more volatility if we moved to retail competition. In many cases, retail providers, my own included, offer fixed-price contracts to customers where we do take on the risk of engaging in the wholesale and competitive markets and taking risks on hedging, etc. In some cases, customers do want that variability and the volatility because they gain from that if they're sophisticated. But in many cases, that volatility isn't passed on in terms of the contracts. Another comment is that you avoided what I think is one of the main arguments for competition, which is economic efficiency and the efficiencies that competition can bring. Are you even working in a world where there's wholesale competition?

*Response:* We had 30,000 MW of bid for a 3,000 MW solicitation. That to me sounds like competition.

*Question:* Who put out the bid? Was it one entity?

*Response:* Georgia Power and Alabama Power.

*Comment:* Competition isn't just about how many players. It's about the efficiencies and the prices that are related to what you get out of those processes. I think you need multiple players on both sides of the equation.

*Response:* I think for new generation, there are multiple players. We've got an awful lot of generation being built in our service territory even outside of the bidding process. We've already got 27,000 MW of interconnection

requests, interconnections that are already underway, compared to a total generation base of 35,000 MW. We're going to have a lot of competition in our service area from generation. They're going to have to find buyers for that generation, and they'll be wholesale buyers because there is no retail competition in the southeast. But there is a lot of competition; there are generators competing to make sales to the wholesale buyers who are municipals, coops, and investor-owned utilities in the southeast. On efficiency, the result of competition should be efficiency and lower prices. My only point was that you can get most of that if not all, through wholesale competition; I don't think going to retail competition necessarily increases efficiency very much. I agree on the first point you made about the ability of retail suppliers to take risk on behalf of customers, but I'm not sure you need customer choice to be able to do that. There would be nothing to preclude you from going to any customer who has a real-time meter and real-time pricing and saying that you'll bill them a fixed cost every month and that you'll pay their electric bill for them.

*Comment:* I want to come back to your uncontroversial suggestion that generators not winning bids should be precluded from building unless they pay all incremental transmission and other costs. You said later that the design you were talking about is consistent with wholesale competition and LMP and all these things can work together. I think the rule you proposed is good if you have an efficient pricing system that, among other things,

requires people to pay the incremental transmission and other costs. And also defining all the property rights, who gets what, and FTRs. What I don't see is how to actually have this rule if you don't have an efficient pricing system and property rights because you can't identify what the incremental transmission costs are when a lot of things are being socialized, and you get trapped in the native load arguments and that kind of thing.

*Response:* I think part of making this work is to have an efficient LMP pricing system.

*Comment:* We're going through retail access in Oregon, to be implemented in March 2002. We've been working through the costs of doing that, the portfolio for residential customers, those kinds of things. But I have to admit that my strong bias toward opening the whole market at one fell swoop versus bringing in the very large customers first and then working through this has changed a lot. When I look at the transaction costs especially of the systems, I'm coming to the point of view that focusing on the customers that can really make dramatic changes is where most of the interest is, and it's where most of the bang for the buck is on the demand side.

*Comment:* You're correct. However, the point is that the very large users who for many years have had the kinds of flexibility they have now haven't really gained a whole lot, so this is not new for them. With respect for those for whom it is new, I agree that we haven't made a lot of progress.

*Comment:* In the early days of the debate, many consumer advocates did not want to allow large commercial and industrials in first. And in some sense, they won the debate. I think we did pass up an opportunity that we could have exploited best, which is bring the big guys in first because they know how to play the game.

*Comment:* One of the things in Oregon that helped us overcome residential versus industrial was a mechanism where you could allow industrial customers to go without shifting costs to the residential customer. The utility still had the obligation to serve and make an offer to take to the market the power that was freed up by the industrial customer purchasing power from another supplier. The utility could then take that power to the market and keep all of the gain or loss. There are some other mechanisms involved, but in principle that was one of the keys. There was avoidance of a cost shift from industrial to residential by virtue of allowing the industrial customer to go. Under your current system, you acquire enough for 15 percent reserves, you have seven-year contracts and you have an additional sum that you get in relation to the purchased power. That would indicate to me that some customers may actually be paying more than if they actually had direct access to the market, primarily the large customers who would have at least someone interested in them, whereas residential customers might not. In the world that you created, why should an LDC be allowed a rate of return on purchased power?

*Response:* It's not a rate of return. It's called in the law an additional sum. I'll tell you why they should have allowed it. Say you're a distribution company only, you don't own any other assets and you're in an area that either is low growth, no growth, or doesn't have a whole lot of growth, you have a declining asset base, the company's going to get smaller and smaller and where are the opportunities for you to make money? Where are you going to get investment dollars because you do have continuing infrastructure needs. I think it's important that distribution companies have a way to attract capital and part of that means they ought to make at least some money.

*Comment:* There are regulatory mechanisms that provide the distribution company a rate of return on investment, but also incentives based on how efficiently they provide the distribution network on a per customer basis.

*Response:* I don't disagree, and I don't think the additional sum is absolutely critical to the whole model. I think part of it was a political compromise to get us to buy into the program, as much as it was anything else.

*Question:* You explained why the California meltdown was not likely to happen in Texas. We know from other retail electric markets that have opened, that there are other ways to fail or have severe problems. Is the Texas model different, in that you centralize a lot of the market-enabling administrative processes like customer registration? You're consolidating ten separate control areas under ERCOT.



These are extremely complex back-office system integration projects. There were some symptoms of problems during the pilot with delayed enrollments, market prices that couldn't post in real time, and so on. Doesn't it magnify the risk of a common mode failure that could bring the entire market down if something is not ready?

*Response:* That's what we're going through before January 1, 2002. I feel that the systems and processes are ready because the pilot was limited to 5 percent. We need to make sure that the systems are scalable. The tradeoff I think is a net benefit because of the advantage of having ERCOT in the middle as a neutral entity and one we can monitor. I think we can also better handle the intra-family disputes that occur among the different sectors.

*Question:* I'm interested in the design of provider of last resort service. Will there be changes in the current prices or their structure once you commence full-scale retail competition and deliver a 6 percent discount to customers? How is the generation component procured? If it's their own generation, how do companies set prices? If it's procured, what are the rules? On headroom, it might be called over-collections from customers by some regulators. What's being done with that revenue and is it a politically sustainable arrangement?

*Response:* In terms of the overall structure, the price to beat is the price that has to be charged. It's fixed – neither a cap nor a floor – by the affiliated retail electric provider in

each region. Apart from that, we have a provider of last resort that is tasked with serving customers that either get switched because they did not pay their bills within the timeframe set forth, or their retail provider went out of business. We're going to revisit that structure to make it more efficient. With respect to the price to beat, the 6 percent decrease is off the base rate component. Then the fuel factor is established independently of the base rate and together those become the price to beat. From the moment it is established forward, it can be adjusted in the event that there are changes in natural gas prices. There's a mechanism where the affiliated rep would come to the PUC and request modification to the price to beat if the 12-month forward strip of natural gas prices was higher than the base price for "x" period of time. So there is an adjustment on a going-forward basis; it's not a static price. As for the political aspects, Senate Bill 7 was pretty widely supported. The tradeoff was to try to strike a balance between bringing the savings to consumers, but at the same time avoiding the disconnect between having just a static retail price and dynamic wholesale prices. Of course the competitive retail providers have to be able to come in under that price and offer the discount to customers. It's necessary for customers to switch. Indications we have received are that it's generally in the 10 percent range.

*Question:* Do the distribution companies describe headroom as actual costs they're incurring? If there were a rate case, would they be able to justify these, or are they essentially

over-collections that have to be refunded to customers, other than on the generation part of the bill?

*Response:* The affiliated electric provider will charge the price to beat. They will, I guess, keep that cash flow. The notion is that they will have to charge the price to beat for a set period, or until they lose 40 percent of their load. It's a tradeoff between bringing in the savings and creating an environment for competition.

*Question:* As you look ahead, do you see adequate incentives in place to deal with the question of where new generation locates, or do you think something more is needed?

*Response:* The fact that Texas had pretty favorable interconnection rates for generation I think helped spur the development we've seen. We are studying different models to understand their impact on a competitive market. For example, what ICAP does do to a competitive retail electric provider, to headroom, etc. We haven't made any determination for the moment, but we're trying to make sure that we keep the vision down the road, given that it takes 18 months to build out of the problem.

*Comment:* The difference in Texas is that there is not a lot of power or generation that's built that flows out. If socialization of interconnection costs makes sense anywhere, it makes sense where just about all generation built benefits Texans. Socialization makes less sense in other regions where a lot of generation is being built.

*Comment:* If 95 percent of the customers and 80 percent of the kilowatt hours are being provided either by the beat-the-price group or by the provider of last resort, and if we have set prices so that they can attract adequate investment in all the words that Brandeis or Frankfurter would have used, including a purchased power fuel adjustment clause, and we give them the tools to put in place a mandatory distribution system with eminent domain and a link to somebody who's doing enough of a transmission grid with eminent domain, and we let them live with a code of conduct which protects customers against the arbitrary actions to disconnect them, by the time we're done, doesn't that look like a traditional utility that has relatively low ownership of generation and special fuel contracts for large users?

*Response:* I don't think you can move from one system to the other that quickly. The price to beat is not a mechanism meant to be in place for all time, but a transition to move from one framework to the other. I agree there's still some complexity to the structure. I think you give competition time to develop before you can just take off all of those limitations.

*Comment:* An additional virtue – whether or not we get many people to move off their incumbent EDU, is that we have alternatives. If the wholesale market does not develop for whatever reason, we can site a merchant gas-fired peaking plant, have it built and finished in a year and a half, close to the load. You know, price is one thing, but if I throw the switch and the plant

is next to the load next to me, I'm going to get the power no matter where it's sold. In terms of reliability, I think the system becomes enhanced because we do have alternatives: transmission, demand side management and generation close to the load.

*Question:* What is your definition of success for retail competition? Evidently, states have goals for the number of customers who move. Is that the test? Is it a percentage decrease in prices from what they would have been under regulation? How do we know when we've won?

*Response:* If we have done no harm by the end of the market development periods, that's a success. Clearly, this was all driven by industrial customers who already had it made, and it's amazing how many have migrated back. A lot has to do with the wholesale market that is low now. The EDUs aren't complaining because the opportunity costs aren't there.

*Response:* I think to some degree the reality is that the litmus test that will be applied rightly or wrongly, is the percentage of customers who switch. I don't know whether that's the right standard. Some would say that the right standard is simply trying to track customer awareness, and the fact that somebody chose not to switch is also a decision. I suspect that ultimately the test that will be put out there will be pretty tightly tied to switching. I'm not sure I agree, but I think that's the reality.

*Comment:* When we started, we had a clear objectives: shift to risk; building

and owning generation from ratepayers to professional risk bearers, and to exploit demand elasticity to make more efficient use of existing generation assets. We could take these two things and promise that restructuring would lead to rates that would be lower on average than under a regulatory system. We will have won when most of the users really have some capability of adjusting their use rates to the price – that's the short-term price in the market – and we have a generating sector that is not integrated either by ownership or control with the transmission and distribution system. So they're independent entrepreneurs, and we have price volatility that induces appropriate conservation practices, and almost all those who can respond to the prices are doing so. In my view, that would not necessarily require that residential users en masse are a part of the system; I think it would require that all those who want to be would be permitted. But I think it does require that commercial and industrials be a part of the system.

*Comment:* We've all been assuming that the very small residential customer, even the small commercial, is not interested in thinking about choosing and most will not choose if they have the chance. You could separate the generation ownership, but you're still going to have some provider of last resort – either managed by a commission or having the EDU as the provider of last resort funneling the portfolio management function through them. Once you accept that these customers are basically monopolized, someone will want to make sure they're getting a fair

deal and you are back in monopoly regulation.

*Response:* I never argued we'd do away with monopoly regulation at the distribution level. The wires still require a regulatory body. It doesn't bother me that a class of small customers is still going to be served by that regulated monopoly; they don't have much demand elasticity anyway. I would argue that anyone who wanted to leave ought to be permitted to go into the market, if they're willing to pay the cost, which means another meter. I don't think we would define success as having everybody in the market. My guess is we could have 90 percent of residential customers still being served by a monopoly, but we put proper constraints as to how it buys power. And it doesn't own the generating assets.

*Comment:* I think that risk has a way of shifting around until it finds its best home. We see it now in natural gas. I can see that happening in electric where we supply you with your need and what your peak demand is and they take all the risk and the EDU is home free. In doing so, they've blended that portfolio with that of many others.

*Comment:* My definition of when you've gotten there is when the children of all the energy attorneys in Washington have graduated from college!

*Question:* My question is a little more serious. Obviously, growing up in PJM, we had LMP and no uplift. Our notion of provider of last resort is

passing along that unhedged spot price because that leaves your delivery company in the position of just delivering and not competing. Now what I'm hearing is maybe it's not so bad to have the incumbent provide what I would consider the most valuable service, which is managing the volatility. Are we changing where we are and learning something we didn't know before?

*Response:* We never really dealt very much with that because it's a relatively unimportant problem. We focused almost all our attention on how to create an efficient wholesale market and get sufficient elasticity in it to make it function well.

*Response:* What happened over the past year or two is that companies themselves are debating whether they want to be providers of last resort. If the incumbent is going to be the provider, then it has to be bidding into that market. The bottom line of the end users is going to be conflict with an enhanced wholesale market.

*Question:* The notion that the system operator who is the backstop for all the demand on the system and has the wholesale market price – somehow we need to say that the wholesale market price isn't the retail market price. We need to somehow force that separation. Why are we going there?

*Response:* We don't have to force it. If the incumbent is the provider of last resort, it has to have the power to back that up and we can expect a premium there to the end user. I think we're fooling ourselves if we think that there

will ever be a time when there's not going to be a regulated entity, be it an EDU or bid out to somebody else to provide that service where there isn't a regulator provider, particularly for the small residential and commercial customer. They're going to have to have a portfolio of resources to meet that obligation and there are going to be rules, just as we have traditionally for vertically integrated utilities.

*Response:* The rules have changed. It looks like there will have to be very explicit arrangements. I don't ever see again a utility thinking that the market itself is going to be the supplier of last resort. I see the beauty of simply having the wholesale spot price being flowed through to customers and allowing customers to hedge it.

*Comment:* My observation goes to the success or failure issue. It also goes to the political constraints. There's very little information content now in the data on who's done what and why. Headroom is just lingo for "We're going to set the price high enough to make something happen." And we've got benefits to consumers which is a euphemism for "We're going to lower the prices like we used to do in the old days." As long as you're in that system, the data you're looking at carries almost no useful information about what might or might not happen in a market. Until those political constraints can be addressed, probably gradually so that market prices can shine through, then you'll get some real information. The value of a market and a price is that they carry relevant information.

*Comment:* I think that's right. In Georgia there was 100 percent switching in the natural gas customer choice program because people were forced to switch.

*Comment:* From my regulatory perspective I think it has changed. Years ago, the error was in the length of time it would take, in part because assumptions were made about the capabilities of passing the wholesale price on to the retail customer. You know, one concept was to drive people to switch by using the most efficient pricing that was real-time pricing. But what they were going to switch was customers who were offered a fixed price that was the most inefficient pricing. The concept was built on having meters and real-time pricing within a certain period of time. I think things have changed because the length of the transition has to do in part with the retail side in real-time pricing and the difficulties of creating wholesale markets. We have created a situation where we're spending a little more time on reality than we were on pure economic theory. I'm not sure that we have to redo or rethink. The wholesale prices seem to be very important to whoever is providing the retail service. What can we do at the retail end to help make the wholesale markets better? Some structural changes and demand-side bidding. The term provider of last resort is confusing because there are two different kinds of providers. One is often called a default provider, but some refer to that as a provider of last resort, and that's the standard offer provider that does provide. It doesn't necessarily pass on the unhedged

price. The provider of last resort is also for somebody whose supplier is now gone, which can happen on short notice. Oregon set up a special, or emergency rate, basically the spot price, because that's what the utility has to go to since it hasn't planned on that load.

*Comment:* In elaboration, it's highly problematic, and you could certainly make an argument that for small retail customers it just isn't worth it, and that they shouldn't be exposed to or participating. Or it should be a regulated entity that can do it better than before. And you have the commercial and industrial and you want to allow the option for these people in the gray band in between to switch. The critical issue is that it has to be a one-directional switch. If I am a small customer and decide I don't like the standard offer and I want to become a competitive player in the marketplace, if I can go back to that standard offer, then you've created an unpriced option in the system and it isn't sustainable and it isn't going to work. There has to be a rule that prevents me from leaving if I'm always allowed to come back, or prevents me from coming back if I'm allowed to leave. And when I come back because my supplier has disappeared, you have the emergency rate where you throw them on the efficient spot price and they deal with that.

*Comment:* For the first year, you can come and go, but after that you do so at whatever the spot price is.

*Response:* Suppose a chemical company employing 3,000 people in a small town purchased from a supplier who for some reason is unable to supply. The company comes back to buy from the default supplier, who can't say, "No, you left, we can't provide you power."

*Comment:* You could provide power at the spot price.

*Response:* If the spot price happens to be really high during that period, the chemical company will have to shut down because it can't afford to operate and you still have the same problem.

*Comment:* In gas and electric, you have municipal aggregations. The township trustees think they're setting the world on fire because they're signing up 45,000 people to a contract without any knowledge whatsoever that if the contract caves, if the supplier caves and they have to go back to the default supplier, their constituents are going to get hammered, and so are they. We made it clear that there was some risk and warned that the price they ultimately may pay could be different from that they're paying now.

*Comment:* There ought to be a recognition that if you have an efficient spot market, anybody who hedges that will, on the average, pay a higher price than those who pay the spot market. Pushing people to go back on the spot market is not necessarily punishment. They just have to live with volatility until they can hedge it.

*Comment:* It also assumes there isn't another supplier ready to serve the industrial load that was just lost.

*Response:* The political concern is legitimate. The implication is that people who are in that category of the chemical company with political clout – and you can anticipate that they have the political clout to come back – should not be allowed to leave.

*Comment:* It's a dilemma and inconsistent and it is the real world. I don't know the solution, other than having a regulated portfolio service that has some reserve built into it that is socialized, unfortunately, that everybody's paying for, that can take customers back if they have to.

*Comment:* Following up on whether the rules have changed, maybe it has changed in the state capitols, but I'm not sure it's changed in Washington. When we have a different view in the two places, storm clouds start forming in the industry because it may well be that some state commissions see an ongoing role for distribution companies managing portfolios as providers of last resort. FERC seemed troubled in terms of satisfying the independent standard it set out for people managing transmission. FERC defines independence as being an entity that doesn't have provider of last resort obligations, and the state tells the distribution companies, "You have to be in the business of providing provider of last resort obligations." We've got a real issue in terms of future policy and how the industry continues to evolve.

*Comment:* In Massachusetts some recent actions by the DPU have actually improved the market conditions. Even though the law allowed standard offer and default service to be determined differently and the default rate was supposed to be market-based, it didn't happen until about 12 months ago. The number of people on the default rate has increased dramatically over time, as it would, from 0 to 35 percent of the total load in the state. Since the default rate has been changed to reflect market rates and for the first 11 months it was higher than standard offer, we're about to see it below standard offer and there's been more competition in the default rate service class. While we've focused on some of the negative things that have happened, we should look at Maine and Massachusetts where there has been a significant amount of success over the past year. I would argue it's because that default is based more on a market-based rate. I do think we have to separate the customer classes and think about separating provider of last resort from default.

*Comment:* What you've described is accurate and I think it's been a little longer than 12 months. Once we set the default rate prices close to the market prices, things began to change. We started off slowly, obviously, in the beginning.

*Response:* Next January through June, the default service rates are slated to go down slightly due to changes in fuel prices. That will be a true test of the competitive market because customers have signed up for contracts that go beyond those periods. Many marketers

are doing “blend and extends” where they’ll change your rate now to reflect the future and keep you below the standard offer rate. People are trying to think creatively about how to react to those price changes.

*Response:* We’re going to start to see some standard offer rates decline, too.

*Comment:* In California, regardless of how clearly you think the rules are that you don’t go back or you don’t renegotiate the deal, if politically powerful economic interests don’t like the way that things are working out for them in the market, they will seek some adjustment. Maybe the most spectacular has been the migration of large, direct access customers, first out of the bundled utility service when prices were down, then back into the bundled utility service when the market went crazy, and then back out once again. In California we didn’t keep the door closed so it was possible to go back and forth. But there’s rational economic behavior on their part; of course they’ll do it. An example where they weren’t supposed to be going back and forth is where people signed up for interruptible programs. They’d been on these for however long the programs had been in existence, 10 or 15 years; they say they were led to believe that the interruptions would never happen, so effectively, it was just a subsidy for industrial rates. Suddenly they were called upon to curtail and be interrupted. The same people who were screaming about the sanctity of contracts when we talk about retroactively revoking direct access say, “Well, I was told that the thing

that I signed didn’t really mean that. And yeah, it’s a contract and yes, I signed it and I agreed to it, but I want out.” If they don’t get relief from the PUC, they go to the legislature. It isn’t just a matter that regulators have the ability to say, “We’re going to draw a line and you don’t cross over,” because we have a political process in this country. The political process is responsive to the very legitimate concerns outlined here. I could list hundreds of major employers such as California Steel that curtailed 95 percent under their interruptible program, but didn’t quite make it to 100 percent, and were faced with hundreds of thousands of dollars in penalties. They’re screaming that they can’t stay in business in a market where they’re competing against producers around the world. If they go out of business, 2,000 people lose their jobs. Those are hard things for political representatives to resist. In our natural gas utilities, there is a core aggregation program, which allows core customers who otherwise receive bundled rates to be aggregated and to go out into the market. Now the past year or so, the market turned a little upside down and people who were exposed were in worse shape than people who were getting the bundled utility service, and especially with regard to pipeline access. The core, aggregated customers said, “We want out of this deal; we want a different deal.” They are mostly schools and some other public entities, but they’re politically powerful and if they don’t get their way at the Commission, they’ll probably go to the legislature and demand some kind of relief. Electricity is different from other commodities



and that just has to be faced. The fact is that California could not stand the exposure to even temporary, extremely volatile, high prices because of the tremendous economic disruption produced. Whether small or large, customers are going to demand some kind of relief, and they're going to go through political methods to do an end run around whatever regulatory barriers may be set up to their retreat from exposure to the market. To believe that it's possible to build walls is quite naïve; it simply is not going to happen. Another comment I'd like to make is that the ability to utilize the least-cost resources and to minimize costs to society is that precisely the same thing is accomplished in a fully regulated utility, except to the degree that it has an incentive to favor its own generation. To the extent that utility-owned generation is minimized to some base-load level that may be appropriate and if there are sufficient regulatory incentives to use that generation when appropriate, it's actually much easier and rational to have real-time pricing in a regulated environment where you know precisely the cost of every bit of the power that is dispatched, compared to a competitive market where frequently it is very difficult to discover the value of the last increment of electricity dispatched. In California, we have the worst possible world because the state has purchased in advance 100-and-some-percent of our power needs for God knows how many years. In fact, we're probably in a situation where utilities may have to provide incentives for people to consume more power during peaks in order to assure that we sell all of the power that has already

been purchased in advance. I imagine that nobody else will do that, but I do think the difference between even a fairly efficient wholesale market and a well-regulated bundled utility is not that great with regard to the ability to make real-time pricing work very efficiently.

*Comment:* On what's changed and why, I think FERC led to a lot of the things that happened that have forever changed the situation. Four or five years ago when we were restructuring California, being in the spot market was not so bad. Yes, it was volatile, but some customers could handle that. Now we're taught that the spot market is a place where people can be harmed beyond anything ever contemplated; that the prices can be 10, 20, 30 times higher than anyone ever conceived and it can go on for months. That was not taken into account when we were trying to figure out how the delivery company or the utility was going to use an efficient spot market to facilitate retail.

*Comment:* With regard to trying to shift the risk of failed generation investments to those making the investment, it seems that if you have a portfolio management function, whoever is choosing that portfolio has the risk. If it's the EDU, the risk will effectively get passed on to customers, although there will be some kind of a split about that. If it's the commission, then it is the customers who in the first instance are taking the risk because the PUC is acting on their behalf. So the very large mass of very small customers are not going to get out from under the risk, whether the EDU

owns generation or just buys it, or the Commission makes arrangements for it, as I guess Texas did.