

**Harvard Electricity Policy Group  
Special Session**

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Cincinnati, Ohio  
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**RAPPORTEUR'S SUMMARY\***

**Session One: Defining the Output of Transmission Companies**

*The various degrees of separation of the old, vertically integrated structures unbundled the products and services that make up delivered electricity. In the case of a transmission company, the new market structure implies objectives that challenge us to define a transmission company's outputs. In New Zealand, this appears as part of an effort to make transmission services contestable and elective, to the extent possible. Virtually everywhere, providing incentive rate mechanisms for regulated transmission companies requires as a first step a definition and associated measurement of what is produced. In establishing the ground rules for transmission investment, an immediate task is to define what is already in place. Such definitions are easy when stated in terms of inputs – miles of wire, numbers of transformers, and so on – but defining the outputs of a transmission company as a list of inputs to transmission service fails to meet the new objectives. The simple idea of transmission “throughput” appears inadequately defined and perhaps lacking insufficient economical meaning. How should the outputs be defined and measured? How robust is the definition, given different configurations of scope and functionality? What performance-based incentive mechanisms could be built on this foundation? Can or should the same performance indicators be incorporated into contracts with merchant transmission entities?*

**Speaker One**

To put it simply, what is the output of a transmission company? Access. If you do not need it, you do not need transmission service. However, most supply alternatives – green power, the value of distributed generation and demand-side programs – benefit tremendously from, or

need, transmission access. The market role of a transmission-only company is both an enabler and the infrastructure to the market.

A transmission-only company does not need incentives to build, but it does need the support of customers, regulators and the public. It also needs a strong cash

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

flow, adequate earnings and manageable risks. In fact, money is the single biggest fuel that a company can burn. No incentives are needed for good utility practices, or new technology, materials and methods to reduce the cost of dispatch and TLRs. FERC incentives, or “FERC candy” is not the basis for a stable business. Anyone who is offered a 50 percent return on equity for a few years is not talking stable business.

A transmission-only company should plan on at least a 10-year horizon and revisit the plan frequently. To give you an idea, my company had about 25 generators in our area for which we planned. Now there are 3 and that has a significant impact. The load growth in the service area is about 2-2 ½ percent yearly.

Transmission projects must be justified, based on need and that occurs in a very public, contentious process. It is easy to stop a project or delay it interminably, which is the same thing, because the costs keep piling up. At some point, you have to give up.

You cannot compete against alternative ways of meeting the same needs. Generation and distribution project proposals have the advantage of a tremendous time difference that is in fact, part of the needs justification.

Currently, we have a nearly \$400 million dollar-225 mile, 345 kV project. By the time we receive the permits to begin building, another \$20 million in costs will have accumulated. If it does not succeed, that \$20 million is a tremendous risk for a small company.

For performance-based rates, the question for the company is whether it can manage the risk better than the customers. If it can, will customers support the incentive service at an incentive price? Can the company keep the money if it does it right? I do not have the answers.

I would claim that there is a lack of regulatory tradition for incentive rates in the US, and we have not yet seen a basis for doing that. We are not against it; we just do not know how to do it.

What are the metrics for transmission outputs? Traditional metrics are inadequate. They should reflect the impact of the system on the customer. Does a company show the ability to plan, license and build to meet the needs and objectives of its customers? Can it keep up with customer needs? The most expensive line is the one you do not have when you need it; all the others are cheap.

We are collecting data on reduced re-dispatched costs, congestion costs, and system energy losses, to give us an idea of the system’s capability. We do not yet have any metrics that are consistent and easy to measure, but we will continue to look.

## **Speaker Two**

Transpower in New Zealand is both the system operator and the regional grid owner. It also has two subsidiaries: Optimal and d-cypha. Optimal, a joint venture, out sources all maintenance and operations of the transmission system, and d-cypha performs the national reconciliation business of allocating quantities of electricity to buyers and sellers. The latter is now one of the largest data management companies in New Zealand and is looking internationally to leverage its core skills. It has just launched the first successful energy futures contract in a joint venture with the Sydney futures exchange.

Because New Zealand has experimented with electricity markets, I will talk about the problem of contracting for new investment, which is a major issue for transmission companies and for markets as a whole. I will also discuss some of the

rules now being developed about the investment decision-making process, and about the importance of service definitions to enable transmission and decision-making to occur within a market environment.

New Zealand has a security-coordinated spot market, security-constrained economic dispatch with nodal prices. Its nodal prices contain constraints and losses. Losses are built in because of the long, stringy grid. There are 250 different nodes around the country. The physical market that produces the spot price actually does what it should; if supply goes down, the perception is that supply is shortening and the price goes up, load is curtailed and we get through the crisis.

Another essential component is non-distortionary access charges. We split line and energy, both in transmission and in distribution. The companies cannot be in generation or retail of energy, and they have non-distortionary access charges where transmission charges do not distort the spot price.

Our lack of a financial market structure around the central physical market that we thought we had means that generators now have no obligation to provide capacity over the long term and therefore no incentive to invest in generation plant and, more important, in primary energy discovery. The establishment of FTRs is the other part of the financial market, and again New Zealand has gone down quite a tortuous path.

Assuming that you have a sound financial market based around a bid-based security-constrained economic dispatch and that you have non-distortionary line charges, you should get market-driven investments.

The problem is that your potential investors may not represent consumer interests. Generators are driven by self-interest and may not locate in the right

place. Beneficiaries always wait for grid investment. Our experience is that generators on the demand side will not operate first. They hold out because of free-riding issues, and they hold out for the grid to invest as a backstop because we spread the costs. Grid owners are penalized for efficient investments. When we have invested to relieve a constraint, we have found that it is very difficult to recover the cost of that efficient investment. A generator located in the area can easily strand it.

You cannot define the service, and so it is difficult to make investment decisions and allocate property rights in an open access grid. FTRs do not seem to provide the total answer. There must be an industry governance system with a public objective at the core of any market.

New Zealand has experimented with having no regulator focused purely on the electricity market. That has led down a path where every entity that acts in its self-interest did not necessarily come up with the right solution. We are concluding that we need a very small core of regulation to protect public interest.

In a multilateral environment on a common grid, people must be enabled to make decisions. We are developing an industry rulebook with nine parts, such as governance, common quality, transport, trading, and clearing and settlement.

Whoever makes the decisions must understand the current level and cost of service, and the alternative levels and their cost of service. Therefore, you need meaningful definitions of service. The first stage is uniform agreement on definitions, measurements and levels for the existing transmission service. We set measures and against the measure, we set levels of the current service. We incorporate these into transmission contracts. Now customers can begin to understand the definition of the terms and from there make decisions.

We also have a framework for agreeing to changes in the current level service. This provides investment decision-makers with a structured, multilateral agreement where appropriate, and a voting structure that prevents holdouts and free riding.

Transmission pricing follows a separate, parallel process that covers the allocation of some cost charges and the new investment charges, again on common services. Very simply, we define and measure the current level of service, deliver it, and then you get paid for that. Payment for the services enforces the rules. And if you want to change your level of service, you negotiate the change and then pay for the new service. Currently, Transpower's customers are the parties connected to the grid, such as local distribution companies, generators and major industrial users. We have found that we probably need to go beyond them to stakeholders like regional development councils in order to make the definitions better understood by the community. Disagreements are referred to an Electricity Governance Board – not yet established – for arbitration.

Remember we separated pricing from setting the service level because the current level of service is not dependent upon the price paid. The price is merely an allocation and does not reflect the level of service, other than on an overall national basis. It was difficult to get customers to understand that. Then the physical contract with our customers sets the service levels where the parties agree. If they do not, we apply what is called posted terms and conditions, and we agree on the definitions within them.

This process results in a draft service plan for agreeing to change expenditure to meet the service levels. Customers comment on the underlying assumptions of the plan, and potential suppliers can then engage with Transpower on investment opportunities. Transpower publishes the

final service delivery plan and then implements it. Transpower is secured for five years by the bypass risks.

Using power quality as a definition, Transpower will use reasonable endeavors to achieve levels of service that relate to power quality points of service. Transpower then places a measure around that which could be deviation, state of voltage or frequency outside of range. It sets the levels of that deviation, for example, plus or minus two percent.

So far, I've talked about the definition of input measures. The output measure comes from the service delivery plan. From the service definition, we build in the customer requirements. They can engage on the assumptions that we have made in terms of service, service definitions, service levels and measures. Transpower has both a ten-year security forecast and a system adequacy guideline. It applies the latter against the current capability of the system and looks for any gaps and they go into the plan.

Since the plan also contains a statement of opportunities, alternatives to transmission can begin to compete on the same terms – because we have closely defined the service – but also be covered in a decision-making process that is broader than just engineers in one room in the central decision-making model.

The government has a statement of corporate intent because Transpower is a state-owned enterprise. We have shareholding ministers; the minister of energy advises both the board and us. The commerce commission price-regulates. We are trying to avoid multi-headed regulation. Our industry rules will probably not be put to a referendum, but we hope the government will adopt the important operational parts. The government may move to appoint a Crown governor's board. Work on service

definitions is on hold currently, pending resolution of the governance structure.

There are lessons around the world from the failures around the financial market structures that we can apply. Get them right and we may get the incentive structures working better. When they are in place, we may well have market-led investment. For that, you need a process in which the market makes decisions. To make those, transmission and its alternatives must be defined in terms meaningful to the decision-makers. We have not solved this, but we have taken a few steps down that route.

### **Speaker Three**

The established markets around the world may all be going through the same growing pains on transmission investment and optimization. I am concerned that the US transmission sector will not avoid the pitfalls seen elsewhere. The introduction of markets is an exciting time for the electricity industry, and maybe we are just hoping for those markets to do too much.

There is no doubt that LMP, backed up by sensible financial contracts will bring great benefits to customers. The big question is if it will also sort out our transmission systems and allow generation and demand to locate in the right places. It seems clear that LMP can do the work on the generation and load-serving side, and is absolutely the correct public policy position. But I think we will find that LMP and the financial tradable rights that back it will not deliver the right transmission investment and optimization because of lumpiness, and free rider problems. If we could discuss this sensibly and honestly, it would help the US move forward quickly. It is crucial because of this country's very low levels of transmission investment.

I believe that market-driven transmission will occur in some cases. I have no problem with a system that allows market-based transmission to be built. But we have to be serious about the backstop, which needs to work quickly and effectively. We must be careful how we knit those things together.

I believe that transmission should be a regulated product, and should be in a position of facilitating the market in that regulated context. I believe the regulated transmission basics are: decide what changes are beneficial to customers; find ways to measure them; encourage those beneficial changes with financial incentives; sit back and enjoy the applause.

The four factors that constitute value for customers are: safety; reliability; correct level of throughput as defined by the LMP-based markets we seek to introduce; and least possible cost. We should always aim for zero injuries every single day, and regulators should encourage good performance by penalties. And there is no substitute in my view for pragmatic benchmarking: setting targets and requiring utilities to beat those targets and continually improve. Reliability should be optimized by regulators holding transmission owners' feet to the fire, and rewarding or penalizing to the extent that utilities are against benchmarks or historical patterns getting better or worse.

Since the market will try to drive power from place to place, the role of the transmission system is to provide the capacity to allow those market flows to happen, and as a minor comment, provide information about future patterns of transmission generation and demand. There is a crossover with the RTO functions, but clearly, one has to decide how much power is likely to flow in a particular direction and put a transmission network in place for that.

What objective do we want transmission companies to achieve? I believe it is a simple question of minimizing a cost function, such as congestion, transmission losses, financing hardware, maintenance and the cost of lost lives. With that, one has to place a value on reliability's customers.

Recently, we spent time and money studying the interplay between LMP, LMP differentials, FTRs and out of merit costs. We believe that the welfare of the system increases by minimizing out of merit costs, not by driving transmission investments and optimization directly off LMP differentials. Investing a greater amount of money sensibly, reduce the implied cost of lost loads and also trades off against maintenance in terms of investing in smarter gear, or gear that might not require as much maintenance. Similarly, I believe that a public process of planning studies – looking at the right amount of investment, combined with a cost of capital or a return on assets that is higher than the cost of capital – balanced by prudent risk will, and is, the only way of delivering the right level.

Cost of maintenance plays off against financing, lost load and congestion. Using PBR to drive down these operational costs can work very well, as long as you also have lost load incentives and PBR on congestion. Otherwise, there is an incentive for these costs to be cut to the bone to the detriment of both reliability and economics.

Cost of congestion trades off against financing costs and maintenance, and should be optimized by driving down the out of merit costs and combining with PBR on maintenance.

If all is done well, it can drive costs down and hugely facilitate the market. The complex regulatory deal pursued for the last twelve or thirteen years in the UK has led to astonishing benefits for customers.

That occurred in an environment where we invested heavily and where the energy costs helped by the almost uncongested nature of the UK system have fallen by 40 percent. While it may not be a pretty answer, it is an effective one.

#### **Speaker Four**

We need the merchant transmission side to identify transmission service outputs: what can be sold and what can be included in a marketplace. The idea in SMD is that people who make incremental transmission investments receive and own the various FTRs, which can be incorporated in other contractual arrangements and be traded.

I think it is a trap to ask what the most efficient investment is over a long term, and whether a particular proposal achieves it. There is no first best solution. We are trying to find things that compared to other available choices work better. If you want to achieve the most efficient investment, implicitly this requires that you protect the people who are prepared to make investments over the long run and also protect the people who choose to play the spot market and then regret it. If your standard is that your transmission investments will protect them as well, that is a difficult task that I do not think we can meet.

One attraction of the FTR product is you can reasonably protect the product, and you do not expose those people to unwanted costs or major difficulties in the future. This is relatively simple to do. If you think of FTRs as the product for the energy market, then there is another market that is also an ICAP market. It is the long-term requirement that you build capacity and generation to meet certain stipulations. As an example, 80 percent of the peak load must have the capability to be met by generation inside New York City. Typically, it will not be met because

it is uneconomic, but at least it would be physically possible. Therefore you must have an installed capacity in New York City that meets that 80 percent threshold. The capacity price in western New York is lower than in the city. If you invest in transmission coming into New York City, then the requirement for installed capacity of generation in the city goes down. You should receive the benefit associated with the reduction in the capacity requirement in the city because of the transmission that you are building in.

In addition to the FTRs, another product you should receive is the Locational Capacity Reduction Right, or LCRPR, in the form of a long-term contract identified by the ISO.

Two ideas that often arise in conversations about transmission are – in economists' terms – the average benefit or the average cost versus the marginal benefit and the marginal cost. If you do not do it, there is a big cost, but if you do, the costs are greatly reduced. We should capture all of the area in between, as opposed to what typically happens. You receive the marginal benefit after you make the investment and you do not receive all of the average benefit along the way.

An alternative is tradable rights for delivery in an ICAP market. It appears to be the logical way to approach this problem. There is an ICAP market with ICAP load that is some measure of peak load in the different locations. There is generation that you will not actually use because it will be uneconomic, but it has to be there physically to meet it if you had to. Transmission deliverability capacity, essentially the logical equivalent of FTRs, now becomes ICAP transmission rights. Setting the ICAP requirement to have the right mix and combination to meet the test of the ICAP market creates deliverability rights that can be traded in parallel with the FTR market system.

This does not overcome the problem of lumpiness, but it does get you out of guaranteeing that you will provide the inframarginal rents through the regulatory system. It also may get you out of having to decide once and for all the future ICAP requirement. The deliverable right is a well-defined incremental alternative for transmission. Conceptually, it would be exactly the same as the FTR, but only apply in the ICAP market.

## Discussion

*Question:* Must we choose between a regulatory model with a market backup and a market model with a regulatory backup?

*Response:* The world that regulates a natural monopoly has not changed. But the US lacks a central point of authority and I see no will to change that. Transmission looks a lot like the highway system and it has the nature of free riders and everything else. I think we must have a regulatory world for transmission with a market backup.

*Response:* We should have a market that first and foremost, gives the opportunity for generation and demand to react to the locational issues that are implicit in our industry. Then if the market does identify opportunities for what we would normally call merchant transmission to come in and be built, and are only being funded out of FTRs, go ahead. I think the chance of getting FTRs to fund investment in a very integrated patch of system is extremely low. If the market will not normally build the right amount of transmission or correctly optimize it, we really need a very robust, regulated backstop. But do not increase the opportunity to stop it from going in for those who will not benefit by the transmission investment. I assume that is in a world where we can simply identify reinforcements that improve the overall welfare. I would certainly like the market

to have every opportunity to put merchant in place as a second element, and then only move to a regulated solution, but I worry about how those two ultimately fit together.

*Response:* You need a backstop, particularly for transmission investment. To me, it is not about regulation itself, but about how decisions are made. Is it a central decision-making role, or is it through active engagement of stakeholders? The latter is what we really mean by market-driven investment. I think they must understand how the decisions are made and the services they receive. If you do not establish service definitions, then a central decision-maker and a regulator make the decisions. If the regulator decides on transmission investment, the generator is effectively deciding upon the location of generation and the deregulated environment we have tried to put in place begins to unwind. We must go down the market-driven path because that takes us through the engagement of true customers. They are the one who must understand the service they will be given.

*Comment:* On a quasi-ad hoc basis, New York has adopted the establishment of a property right for deliverability. It is called an unforced capacity deliverability right, or UBR. It must be coupled with a physical asset or some reliable form of generation to be recognized. UBR entitles you to have capacity from a remote location acknowledged as contributing to a local reliability requirement as established in New York. It does not entitle you to the integral of the shift of the supply curve; it entitles you to participate in a clearing market in that location. I guess that a CBM-like value may be created, and neither PJM nor New York recognized that. CBM, or capacity benefit margin, is the reliability of diversity from joining two separate ISOs or control areas. As I read the SMD proposal, the probable benefit would go

away. The only way to recapture it is to increase the footprint of the ISO. To the extent that it is there in PJM and New York, it is frozen, and incremental property rights that are created are on top of that frozen level. New York has had some real examples. The ISO put it in and did not freeze it. It took the diversity benefit. We all complained, and now it is being implemented.

*Question:* What will macro-economists and investors be looking for a decade from now? Will the National Income and Product accounts contain a separate line for the transmission sector? Assuming there will be independent companies and that transmission will remain bundled for some time to come, is it really feasible to look at transmission as a separate part of the economy?

*Response:* As a research question, it might be interesting to ask how the national income and product accounts will treat the sector when it arrives. The question is relevant because it guides us there. When we define the product and begin to sell it, the revenues will be used as a measure of the product. Ingo Vogelsang recently conducted a survey that he applied to transmission companies. In theory, he asked how it could be consistent with the national income and product accounts. If  $Q$  is the output of the transmission companies and supposing there is a completely unconstrained transmission system, the output will be some kind of throughput measure. Vogelsang analyzed how to provide incentives, using the best ideas that we know of today. Next he asked what happens if you really do have constraints, congestion and multiple products. He wanted to see if the system would satisfy some technical conditions because then you would not have to be so careful about planning it. There are complicated tradeoffs in defining the products and in providing the incentives. We do not have a very good definition of  $Q$  and there is no perfect solution. But



with SMD and FTRs, and if there are ICAPs, the UDPs are moving in the right direction. I worry about outputs that are not well captured in the marketplace. Often they fall into the category of various failures in market design. A simple example is that of output that is measured in terms of the real power flowing and there are voltage constraints at the ends of long lines. Reactive power availability will limit the amount of power that can be moved down the line. There is no signal to the market because the voltage constraint is not represented explicitly as a constraint that should be priced in the spot market. Should we make regulated investments to eliminate the voltage constraints so more real power can go through? Another way to do this is to say that it is easy to represent the voltage constraints in the real power market to reflect the fact that when constrained, the price should actually be very high and that would allow the signal to go through. The FTR product would capture that effect about as well as you can. Part of our work is to make the market price more and more of these things. But the current definitions and the products we have are imperfect. We grope to make both better matched, and then we have the backstop.

*Response:* To have a business, you need a contract. To have a contract, you need a price, and you need to define the service.

*Response:* I have not given up on defining Q. The definition is multiple products and multiple outputs of a transmission company. There will be an “other” category, but if you take out FTRs, UDPs and so on, you will get a more articulated model.

*Comment:* We have the ability to model all of the constraints and therefore have a perfect market design. But do not confuse our different roles and perfections. Even if you model the constraints perfectly in your LMP algorithm, you still have the problem of the financial outputs from that

in terms of transmission optimization giving an imperfect answer. Remember that transmission is unlikely to react perfectly because of free rider and lumpiness. The reality is that transmission is regulated all over the US. The issue is whether we want good or bad transmission regulation; I am sure we cannot have no regulation. Because we keep hoping that the markets will make it all go away, we will not get good as an industry at regulating transmission to drive the outputs needed by the customers.

*Comment:* It is too facile to say that lumpiness and free rider issues will make everything go down the tube in trying to award incremental property rights and make things consistent with the market. There may be some points at which market values take place and require some action. In New York, we do not yet have generalized procedures. But we have agreed on a general approach. There are examples of divisible projects that function. They may not make it economically for other reasons, but the mechanisms are in place. This is a tractable problem that people can handle within the markets where there are capabilities to define real property rights. In PJM, another design structure allows the expansion of the transmission system associated with new generation. People feel reasonably comfortable about measuring what happens.

*Response:* Because one or two projects are going ahead, do not assume that we will get the right amount of transmission. In many US states, transmission is replaced about once a century, but it does not last that long, and congestion is going up.

*Response:* We can argue about whether we have done enough, but the baseline of not enough grew out of a regulatory environment where none of these property rights were explicit. Where we have begun to create the rights necessary for people to proceed, we are only now seeing the

investments begin to occur. The rules are not yet fixed. Conclusions about market failure or insufficiency of investment with respect to market designs built around an LMP FTR structure are totally premature. If there has been a failure, it is where people were offered rate-based guaranteed returns under state regulatory authority, and things have not been built. It is not necessarily bad behavior. Things like retail rate freezes tend to influence people's behavior about making new capital investments.

*Comment:* I worry about that argument because we should go forward with a sound academic understanding of what we expect for the right answer in something as important to the country as this. Then we should see whether it is actually working.

*Response:* If we define the transmission outputs in a way that allows customers to decide to buy it or not, we are in serious trouble. The US does not have even an approximation of a monopoly because there are multiple companies, multiple operations, seams issues, loop flow and other complications. Therefore, it is difficult to define what these groups are supposed to produce. The other endpoint that it is only regulated investments is unacceptable because it is the slippery slope problem, and could completely wipe out everything with respect to SMD. We need to define the products and draw the line between the two kinds of investments in a way that is stable and accomplishes what we are trying to do.

*Comment:* On the one hand you say that it is clear that the markets alone will never get us as much as we need of Q, and on the other we have no normative guideline as to how much we need, other than the mantra that since we will never get enough, there will never be too much transmission.

*Response:* Whenever we build, there are winners and losers. Obviously whoever takes advantage of congestion as market power becomes a loser. Ultimately, greater access seems to benefit the buyer. The two issues are: what does it take to build, and what is the best way to allocate what we have? It is not about building everything we ever could, but as long as need is the criterion, we will never build what we do not need because it is easy to stop it, and in fact, it should be stopped. We should not build when we do not need.

*Response:* We can argue over the details, such as the different nature of a generator's solution to a regulated transmission solution, or the discount rate that we could apply. We can do an academic exercise, and weight the various uncertainties. If you calculate sensibly, whether you will get to the same amount of transmission capability with FTRs and market response. I say we would expect the backstop to bring forward most transmission investment in an already integrated system. Do not design the process so that we get to the backstop in ten years' time.

*Comment:* Can we just build more and more? It must be based on the needs of the economy. You have to talk to people, not just calculate the need. What we are talking about here is how to get the electricity industry around the world to focus on the needs of consumers, and thus the economic aspirations of the regions. We must have meaningful definitions and translate the needs of the communities back into the industry.

*Comment:* There is a self-regulating mechanism that is not captured in any of this market analysis or modeling that simply will impose a real-world practical lid on what is built, irrespective of what our models tell us or the markets suggest. There is nothing in place currently that suggest that any of the market procedures or processes will overcome state siting

issues and the other factors with which we have grappled for years, and that this discussion does not even begin to address.

*Response:* If you have a market model, you would ultimately go to contracts with those communities to provide the transmission investment and service. If you have a central planning model, the regions would lobby politically to get the investments in their communities.

*Response:* Transmission companies do respond to long-range requirements and expectations. This is where the messiness of transmission planning comes in, and it is a messiness that is very constructive. Like most good things, it is not quite straightforward. Elected officials, development groups, large customers and regulators become involved and we have to integrate their needs also. We have to be there before the load is because the load can be built far faster than we can build the transmission. Just-in-time transmission is a disaster for the economy of an area. If you do not serve that economy properly, you do not have a business. You look at a variety of factors, not just a single price signal. You are expected to do that because a utility is part of public policy and implements public policy.

*Comment:* Of course we must have an open planning process in which communities can represent what they hope for the economic development of their area, and where there is a real dialogue with customers, people who grant rights of way, and so on. I do not believe that you will discuss this without that economic case. I think it is incumbent on us as transmission professionals to make sure that we justify economically what we propose to do.

*Comment:* Making the economic case must always be made to either a regulatory body or a lending body.

*Question:* Instead of a PBR plan, which is difficult to implement, especially for a transco, could you live under cost-of-service regulation, but modify it, for example, to give premium ROEs, sell a rate depreciation or reduce regulatory lag?

*Response:* We would like to see PBR happen, and how we could measure and incentivize it. In a PBR with potentially higher ROE, you have to make sure you can handle the risk. Over the last few years, utilities have been attracted by the higher ROE's, but forgot that the risk was also growing. You have to identify the balance between potential earnings and the risk. Frankly, if you control the risk at the same earning, you have a higher volume business. We have not yet found a PBR that works.

*Comment:* Part of the problem is defining output. Also, it is difficult to align the interests of a transco under a PBR plan that is consistent with the interests of society as a whole. A transco could also monopolize information, which could stifle the development of a good PBR plan somewhat.

*Comment:* The externality effect makes it much more difficult to design a PBR for gas or electric distribution. It is the nature of the beast with transmission.

*Comment:* There is a lot of PBR in the US. It is called rate freeze.

*Comment:* PBR on operational costs is almost universal in the ability to drive up the ROE by managing their costs under a rate freeze. Then we get the CPI minus X issues that are really only elaborations on rate freezes. PBR on operational costs is doable. PBR on congestion is really for the heavyweights. It has been successful in the UK, but it was difficult just in setting benchmarks and trying to beat them. It is more difficult in the US because of fragmentation. You cannot measure costs directly for each

transmission owner's footprint. Even if you could, whom do you measure first? And if the owners are taking actions simultaneously to drive down congestion, who receives which bit of the cake? If you can identify congestion benefits across the whole network, and tell the transmission owners to decide among themselves who will get what, and you receive nothing if you cannot decide, it just goes back to customers.

*Response:* PBR in New Zealand used ODV and ROR regulation on the grid. We could only earn a regulated ROR based on the valuation of the assets. We could not charge an ROR on their historical costs. We could only charge for the optimized grid. Under ODV, if you make an investment and the better alternative is local generation or reconfiguration of the distribution network, then we must devalue the existing assets down to the point that they meet the competition. ODV is probably the single most significant factor in stopping transmission investment going forward in New Zealand. If the system does not make investment decisions very cautiously, it faces stranded investments if there is another economic solution. We are now moving to more conventional price regulation. All line companies will come under CPI minus X and the X threshold will be decided by the Commerce Commission, based on what it perceives as the companies' efficiency. The danger is the twin heads of regulation. A regulator defines service and the contract defines the service potential. Can we actually share the risk with our customers? If we can, we will get a more efficient solution.

*Response:* The idea that you get to charge for what you should have done as opposed to what you did has a competitive market character to it, but it is asymmetric. The original idea was that a regulated entity could charge for what the optimized network would be.

*Question:* How do we review the prudence of the operation, including investments, by a transmission company? What should the TO be held accountable for, as opposed to an ISO, neighboring transmission or RTOs, or state siting authorities? Suppose an ITC decides it needs to site a new line and the state turns it down or the ITC says it needs to site the line, but since it will be turned down, it will not apply for it? What does a prudence review look like and how do we do it? What if today or for as far as we can see, we do not need transmission capacity? Is it possible to do in transmission what we did in generation, which is to disallow the costs, but if you can recover them in a market, you can do that?

*Response:* I think a prudence review is already faulty by its own definition. It is very difficult to build what is prudent and needed. Certainly, you have an internal approval. In many jurisdictions, you also need an external approval. Building something that is imprudent is a disaster for both the investors and the public.

*Comment:* The issue of having a forward market might be relevant here.

*Response:* If I were a regulator, I would first look at what is in contract. The first prudence test is that if everyone is happy, the regulator should leave it alone. I would want transmission plans to take into account the economic and development needs of a region, and not just the technical aspects of the transmission system. Next, will the plan actually deliver? Will TOs deliver and will they be paid? There are major issues about enforcement of transmission charges and cost allocations. If it is not in contract and cannot be, then this is about the production and execution of an investment plan. New Zealand's customers can see the full impact of nodal pricing and the spot price, but we lack the financial contract structures around that market to enable customers to manage the risk.

Unfortunately, we are a manufacturing industry that tends to be 100 percent exposed to the spot price. Initially, industry loved this because there was sufficient generation and competition and the price was low. Then a dry year came along and the price shot through the roof. Now industry wants full hedge cover. Customers who are negotiating short-term contracts find that they are either very expensive because of the built-in premium, or they are unavailable. Meanwhile, residential customers are oblivious because they are fully protected. Without long-term contracts, there is no obligation to provide capacity for the generators, who just pass the risk off to the consumers. They do not make the investments in primary energy development.

*Response:* If you only set benchmarks for operational costs for congestion and so on, why would you need a prudence review? In terms of a capital program, I think it is less clear that you can set up a very satisfactory balance. Some reward above the cost of capital is in order if you want things to be built in this regulatory paradigm. How do you make sure that companies do not chase that to a degree of gold plating? Is it to the customers' benefit overall, to build a new facility? Is it being built efficiently? I expect there would be a sensible, creative tension between regulator and regulated company. A transmission company's natural reaction is to tell the regulator that looking into the future is difficult. "We have analyzed this pretty carefully and we wish to demonstrate to the community as large and to you, our regulator, that a project should be built. We used such-and-such assumptions. Do you have a problem with them?" If the regulator replies, "We engaged in the debate with you and we think that your assumptions are pretty sensible overall," that is probably good

enough in terms of evidence at a possible subsequent review that it was regarded as prudent at the time. If the regulator replies, "Your assumptions are not very good, but go ahead if you like" the regulated company takes its chances, and may end up with stranded costs. I return to my mantra of setting up sensible financial incentives. Make the regulated company come forward with its capital program and regulate it carefully. Set an amount of money to deliver that capital program. If it beats that, the company will be better off.

## Session Two. Drawing the Line for Transmission Investment

*There is an inherent schizophrenia in the evolving approach to policy for electricity transmission investment. A stated goal is to allow for merchant transmission investment in response to market incentives and without direct rate base protection. At the same time, most would argue that merchant transmission cannot meet the need for all investment, and more traditional rate base investments will be required, with or without participant funding. We need not, for purposes of analyzing this question, resolve the debate about whether most investment will be one or the other. However, ruling out the respective endpoints requires a framework for coexistence. Moreover, the treatment of rate base transmission investment could have major implications for electricity-related investment in general. We know that managing simultaneous regulation and competition is difficult in the best of circumstances. Given the complexity of transmission, is this problem just too hard? Where and how do we draw the line between merchant and rate base transmission investment? What services/investment opportunities should be contestable and what should not be? For example, could a merchant provider add capacitors or transformers to the pre-existing lines of a regulated transco? Should an unregulated affiliate of a regulated transco do the same thing on an unregulated basis? Do the investment principles match up with the service definitions? What other electricity restructuring dominoes might fall, depending on the choices?*

### Speaker One

When generation or demand-side siting is in the correct locations and LMP exposes the prices, suddenly the problem of under-built transmission becomes smaller. However, there are issues about whether merchant and regulated transmission can coexist. I think two conditions must be met for merchant: that it is a voluntary investment, and that it is not in rate base. I also believe that there must be a regulatory backstop because of things like market failure.

Unless we have pricing, we will not know if merchant investment can occur. We should be careful when we say that no one is investing in transmission, because it may be in an area or it may be a case in which lacks the price signals to drive any merchant investment.

One business model is voluntary non-regulated, or non-rate base investment, and that is merchant investment. The other has what we could call mandatory and regulated returns. But what do we do with

things that are voluntary but want to go into rate base? We need to think more about the hybrid – voluntary and regulated – that makes no sense once we have market signals.

Still another issue is whether one can impose regulated obligation on merchant participants. You could say that you cannot erode that particular investment. There are prudence obligations or performance obligations you would want to put on the merchant, but to force a merchant to do system expansions, as you would a regulated, traditional-style transmission owner, is literally, a disconnect.

In the RTO debate, what happens when there is no builder of last resort? How would we do a transmission upgrade? That problem must be solved before the start of an RTO. Another practical problem in this debate is that centralized planning requires a central coordinator. Once there are markets, a return to IRP will interrupt the market activity. It appears obvious that you need a well-functioning market if you

want to move toward market-driven investment. Its planning functions can even be a bit light-handed. So far, experience has shown that when markets are not working so well, there is a very intrusive, command-and-control central planning function. Maybe transmission planning is replicating what used to happen in generation. When a plant was needed, everyone could bid on what it would cost to build. If we go down that path, it is not a market-driven one, even though it may be a competitive path with maybe a little “c” on it. When you actually erode the carrying capability of the grid that is a problem. Finding the balance that preserves physical or financial rights is important.

A new idea is PJM’s order that it will identify unhedgeable congestion. If I want hedges through FTRs and none are available, that is unhedgeable congestion. If FTRs are available and I do not take them, that is hedgeable congestion. FERC has been insisting for a long time now that PJM give such things an extra boost.

Winners and losers are created when you force upgrades. If the ISO is supposed to be neutral, is it appropriate for it to identify upgrades that help some market participants, but harm others?

The more we try to make transmission non-merchant, non-market driven, and the more we intrude in what could be competitive investment, the more we make sure that TOs will not be in the market and find market-driven planning solutions, or even operating solutions. Putting central planning on the backs of the transmission investors keeps them in a neutral role. We may miss some opportunities for technology and innovation that otherwise might have come through more private funding, more private investment because we do not have the market signals driving investment as much as they could.

## Speaker Two

The heart of the debate is whether transmission expansion investment is contestable. Grid operation is a bit like piloting a plane; only one pilot can fly at a time, even if there are two or three of them up there. Only one entity can physically manipulate the grid, run the control area or the systems operations center at a time. It does not have to be the same entity that owns the assets, nor does the same entity have to do everything.

Hypothetically, where would one draw a line for investment? It ought to be the existing regulated asset owner. With that goes the obligation, from a public utility standpoint, to replace aging or failing equipment and meet the requirements imposed by NERC and other organizations like RTOs.

First, regional facilities need to be declared regional by some entity, probably an RTO. Then, generally, projects would be large, reasonably discrete facilities, including major new lines, even 765 kV, due to their energy-carrying capabilities, and the regional impact of almost any addition at slightly lower voltage levels. In the mid-1990s, when Alberta was restructuring, it created a Transmission Administrator. Until 2002, it interpreted the provincial law to require the contestable bid on all greenfield additions to the grid and all additions in the utility’s footprint above ten million dollars Canadian. The market rules did not allow the regulated utilities to bid for assets in their footprints. Four bids were tentatively awarded. The resulting uproar from the utilities, market participants, stakeholders and the government caused the energy minister to pull back all the bids and assign them directly to the TO in whose footprint they resided. While Alberta has not completely scrapped its contestable market, it is rethinking the size of contestable projects.

I think the issue of who builds is easily decided, using the template I have described. The bigger issue is who gets the rights. If this is not thought out up front, you will have the same free rider problems that the early IPP entrants rushed to gain. As with any infrastructure network, the first to propose fixes are likely to create some of the largest rights allocations for their investments and there will be a strong lobbying effort to keep those rights. New mechanisms and entities will arise, and if the right framework emerges, they can be used to solve the problem in certain circumstances. Perhaps it will be the RTO.

My point is that the investment rules must be reasonably clear, whether you are in the regulated or merchant investment camp. Attracting capital and debt for true merchant additions would be difficult. To reiterate, you must solve the rests allocations issue if you want to solve who builds the regional facilities.

### **Speaker Three**

Some of the practical issues we are facing may suggest certain areas where we will not proceed on a merchant basis. The real questions are how to integrate the market-based objective and address the limitations. Can we set up some preserves, reservations or subsections of activity that, when coordinated with a backstop, will satisfy all of the requirements for the transmission grid, while still offering reasonable opportunities for merchant and private investment?

Unfettered central planning, reliability and the economics will destroy merchant transmission and other things that we are doing. We need to know where to draw the line and where FERC's incursion and rules come into the planning process. If we do not draw that line, it will cascade into a fully centrally planned system in which SMD's only function is to ensure that we have an efficient spot market.

What is wrong with a fully centrally planned system? If there is the potential for someone to offer a centrally planned solution that adds something independent of any externality or reliability issue, it degrades the rights held by the existing market participants. For example, if I build a generator, I might expect that some generation will land next to me and that I will experience a competitive impact that will reduce my profits. I may even expect, under reasonable circumstances, that a transmission system to support reliability-based expansion might change, and therefore the value of my generator will shift. I do not invest with the expectation that everyone will say, "I don't like the prices." We socialize investments in transmission or generation for that fact. That is our hard and fast rule.

The moment we step over the line of devaluing people's rights in an ad hoc fashion through socialized central planning, all private investment will disappear. We also remove the major incentive or loads to hedge by a transmission expansion, generation contracts or associated rights. Why would I pay for something if I can sit back and complain, and get the costs rolled in to my zone, region or something else? The worst I can do is pay for it myself and I can only do better by delay and complaint. Bilaterals go out the window and no one does anything on a private basis.

What if I was prudent and entered into a long-term bilateral arrangement, but the entity next to me did not. It complains about too much congestion. Because it complains, we build and charge everyone in the zone. Except that I already entered into my hedge; I built the generator; I paid a premium to someone else to deliver to me. Now you want to charge me again?

This requires that the ISO or RTO take a forward market position. If so, how do you decide what is cost-effective to build? The only way is to have the planner step



into a forward position. On behalf of all market participants, it trades off capital investment that is the future expansion of the system for energy savings. But we have killed all the private investment and are back in the world where the guy who makes the centrally planned transmission investment is really planning the entire system. Therefore, we need to all be aware of the consequences of saying we will have economically planned transmission expansion.

Listen closely to the people who argue about the need for economical transmission expansion, and you find they are talking about who pays. When they say they want central planning and rolled-in expenses, they are really saying, "I want a benefit and this is a way for somebody else to help pay for a portion of it." It should not be lost on the regulators that complaints about a shortage and facing congestion are really about who pays.

Of course, the beneficiaries should pay. Everyone likes that. But the default is not that simple. In fact, the people who typically are the beneficiaries usually argue for a lack of precision in figuring out who the beneficiary is, and want the largest and broadest socially beneficial group to pick up the cost. In reality, figuring out the beneficiary in an equitable fashion is a tough problem.

Another example is when I buy a hedge, but my neighbor does not. The ISO justifies an upgrade – taking my forward position away. When it assigns the cost of the zone, I point out that since I already purchased a hedge I should not be charged.

Figuring out who pays is exactly what the market tries to do: find the mechanism that assigns the cost to the entity that is unhedged – the victim if you will, of congestion. If I will be that precise in

trying to assign the cost, why would I expect the bilateral not to work?

We assume that there will be situations in which the market will fail and this will not stop. But there are many situations where it will. If we look at it this way, the ISO could perform different functions in the planning process, such as possibly providing the data and planning assistance to coordinate. Yes, there is only one entity that makes the long-term decisions about the system's expansion, but one thing that should not be done is to direct where projects should be built absent a market failure.

There are a few alternatives where we can draw the line. I think this is a viable process, although it is being undercut by FERC. To make it work, we need a preserve, a protected area. I receive known property rights. I know the risks and benefits. This does not mean that I do not face competition from planned projects, but it means that I know the criteria that will be applied for someone to build a centrally planned project. Even if this protected box is shifted or changed because of other regulatory backstops, there is a role for a merchant transmission function.

There will also be situations that only a central planning function can resolve, for instance in terms of reliability constraints that will not be visible directly in the market prices, and when there may be significant economy-of-scale free rider issues. And once we direct something, it should be a competitive process: competition in the directed reliability or directed market values. This is reasonable and desirable.

Ignoring the larger problems for a moment, this sounds like reliability or economic upgrades. PJM has had to distinguish and engage in transmission planning for years on reliability upgrades and they have never used the word

congestion in terms of an economic concept. Clearly, we can plan without every knowing anything about the economics of congestion if we have a set of criteria that can be used with anyone's baseline plan. These upgrades will result in economic impact, but it is a known and knowable risk. We know the criteria. Everyone can go through a planning exercise. If done well in advance they tend to send leading signals to the generation side.

New York has a straw proposal to measure incremental rights for both AC and DC in terms of expansions on the system, a set of rules for allocation and a process. People are asking for FTRs for PJM's upgrades; the ISO will be awarding them as part of the expansion process associated with new generation. Given this background, there be a straw if we establish a baseline for upgrades that reflect the reliability upgrades, and put in the significant market values, to the extent there are any. Then we post the plan with reasonable notice, say, five years' lead-time. Allow merchant transmission and generation load management to do what they want until the last time that is feasible to implement what the baseline contains. The ISO can then re-evaluate the need. After that, bid out the remaining baseline projects. By default, they could to the TO. Everything else – the projects on the bottom – is essentially merchant.

The bad news, however, is that FERC's December 2002 order wants a solution that does more than identify failures; it should provide information to facilitate directed economic expansion through a central plan. By directing us to mandate the undertaking of economic expansion it sets the line far over to the side of central planning. I think that FERC has fallen for the argument that LMP and SMD have failed to resolve the problems of inadequate transmission and congestion, but the reality is that if there are inherent problems in under-capital investment in

the current infrastructure, it is certainly not a function of LMP and SMD.

To the contrary, we are passing all the NERC reliability standards in every area of the country. Those who say the system is inadequate are viewing – through LMP and SMD – the fact that they have been subsidized; that there has been congestion in the areas where they are being served and they have never had to pay. They can say either, "I really think you ought to maintain my subsidy," or "I think there is inadequate transmission." From a political perspective, it should be obvious which argument is made. I will be the first to admit that we have limited empirical evidence of what happens where there are price signals.

I think that the property rights structure has probably eliminated most of the economic transmission expansion in PJM for merchant. I think merchant residual has just about disappeared because of this, which is a huge success. When PJM put a queue in place for property rights for merchant transmission on a stand-alone basis associated with generation, there are now 17 or 20 projects in the queue.

#### **Speaker Four**

My concern is that interjecting some of these issues into the dialogue of why form RTOs and why move to LMP and why SMD makes sense makes people even more nervous. In my view, part of drawing the line is timing when to begin to talk about merchant transmission as an alternative to traditional transmission.

The problems we are trying to solve are first, fragmented grid ownership and operation. As you move west in the US, there is more public power and more cooperative power; there are both jurisdictional and non-jurisdictional transmission owners. There are vertically integrated utilities and IRP in some states

that do command-and-control regulation. You do not yet see many efficiencies relative to what occurs when transmission is under common ownership and control and can drive efficiencies in how you operate the grid.

Second, there is insufficient investment in the system. Many companies are under price caps. And Byzantine siting and certification processes and local opposition continue to be very challenging. These will all stymie merchant transmission more than anything because I cannot figure out how anyone will raise the capital with these uncertainties.

Then there is the dichotomy of inconsistent state and federal policies. Do we even want wholesale competition, or are we backtracking? There is a lack of confidence and uncertainty about the benefits of what has occurred in wholesale markets. The lack of market signals will be a real challenge in terms of grid-deepening investments. I do not see having someone build on to the existing incumbent system more capacitors, transformers or upgrades. Deciding when to take a line out for maintenance will affect someone else's FTRs and there will be fights. How do you allocate the FTRs in a system that is so stochastic? How do you value them when you are just beginning to allocate them? In these developing markets, what are the opportunities for new AC or DC investments?

If transmission investments are lumpy, how much should you build at any one time? You do not build just to meet enough. You need to build for what you will need in ten or fifteen years. I think it will be challenging to finance that on a merchant basis.

Another issue that arises continually is about whether we are building transmission to serve reliability or

economics. If it is the latter, many people do not want it.

I think our focus really must be on getting a workable market, particularly in regions of the country that are suspicious of markets.

We need to focus on policy. How can we consolidate the grid, either through RTOs or ITCs? We will not get from today, where a local community can oppose a transmission line that has gone through several state processes to building merchant transmission until we grapple with today's planning and siting laws. I propose that we look at pricing transmission in a way that provides the right incentives and take that as a first step on a continuum, rather than moving to what I think is the most developed state for merchant.

## Discussion

*Comment:* A certain amount of subsidization and socialization is public policy in this country and it will not change. In other words, we cannot necessarily allocate costs to those who in fact incur them because the public policy will not allow it. Congestion that becomes economic very often becomes reliability. The central northwest has a load pocket with three nuclear plants of 500 MW each. A single phone call can shut all of them down and you can go from economic congestion very easily to reliability congestion. That could create a major panic in a fairly large portion of the region.

*Response:* Some subsidies are inherent. My preference for rural electrification is that if you want to subsidize coops or municipals, tax people, send the money back and let them pay the same price for electricity as everybody else. I think it is insane that by organizing a utility into a muni, it receives federal preference, but

the guy across the street who is served on the same system does not receive federal preference for things that he has paid for in his tax dollars. If you want to pick people to be winners and losers, you will distort the prices. If you distort the prices and say you will subsidize people, I would rather see it be visible. If you want to make it visible, then you would not change what I have said, and the same goes if you want to make it a constraint. If the constraints are set so that we have both an adequacy requirement and NERC standards, the two are the full contingency set we consider all the way down the line. As for economics versus reliability, if it is not picked up in the combination of the adequacy and transmission contingency rules, then we are not seeing it today under a regulated system. Does someone in the northwest plan for losing nuclear licenses all at once today? I do not think so yet.

*Comment:* It was thought to be such a low-probability event that NERC did not highlight it, but it did occur in 1997. It is now something to plan around.

*Response:* When you plan more contingent criteria than your operations criteria, you will see much less congestion and you will not receive the right price signal. That may mean more market failures. The line definition remains the same, but investment on the merchant side shifts to the planning side. If you must have deliverability so that if your five largest plants in the system go out and everyone will have adequate transfer capability, it will change the reserve margins. It will also change the baseline transmission plan and LMPs will not indicate congestion if you do not operate against that. Probably almost everything will end up in your baseline reliability plan.

*Question:* The short-term problem is the need to build new transmission now. The long-term problem is the need to develop

a process for market financing for new transmission. Will we have to wait a decade for the market to demonstrate that it will not respond before we can proceed with some kind of directed construction? That asks too much of the public. Could we get the short-term process going, yet eventually reach an adequate market response?

*Response:* In its compliance filing to FERC on March 20, 2003, PJM says that it will undertake to incorporate the evaluation of economic opportunities for expansion and put them into its plan, and begin a process to track congestion. At the appropriate time if there is no response from the market, PJM will direct an existing transmission owner to make the investment. PJM is perhaps one of the only systems in the country in which there has been central reliability planning long enough so that if tomorrow no one did anything, the system is perfectly reliable. Saying there is insufficient transmission has resulted in people being directed to undertake socialized investment. This is a political result that is inappropriate. There may be a legitimate socialization argument for a situation in which reliability standards shift when certain transmission facilities are transferred from local control to the operation of the ISO.

*Response:* We do not yet know the unintended consequences of putting the central planner into a market role, or how that corrupts the market investment that would have been undertaken otherwise.

*Response:* For a reliable system, you can have a set of fuel prices and/or a set of modified heat rates that will make congestion go to zero. You do not add any generation or transmission. What I am suggesting does not prevent a state regulator from directing a local TO to build; personally, I dislike the state taking a forward market position.

*Comment:* States already do that to some extent by imposing the residual revenue responsibilities on customers in their states.

*Comment:* If you argue that once you have resolved the reliability criteria then everything else is market-based, I predict that the working groups by which reliability standards are now determined nationally will suddenly have high-powered attorneys sitting in on them. I agree that when RTOs take over, operations will become more conservative and investments will increase.

*Response:* Defining the level of service and the process for transmission is about establishing reliability and capacity, not about relieving congestion in the marketplace. If you want anything else, you have to contract for it. There should also be a common set of embedded rules that everyone understands. There is an issue only when someone is out of compliance, or if we shift the rules.

*Response:* We may be talking about two models here: the owner/operator, and one in which the owner is separate from the operator.

*Question:* How could we get more demand side participation by creating property rights both on the energy and transmission side for consumers?

*Response:* If consumers invest in the grid, they get their property rights back in the form of FTRs. However, in most cases where we have had wholesale restructuring, the retail prices are still fixed. What we might call competitive offerings is expected to be at some kind of fixed rate. The real electricity-clearing price is not passed through to the end users. In New Jersey, we hope to tie large customers at least to market prices. We expect it to result in more demand response. It would appear that LSEs do have the incentive to find more efficient

ways. In PJM prices have declined and there is so much supply-side response that it is difficult to know what the cost-benefit breaking point is for demand response.

*Question:* If I were a small business, would I have an FTR if I had paid the embedded cost of the grid as a consumer?

*Response:* You should be entitled to an FTR.

*Question:* Would I get the rights allocation, or would my retailer?

*Response:* The retailer who purchases from the market on your behalf receives the entitlement to an FTR or an auction revenue right, depending on the model.

*Question:* If I want to install an energy-saving management system in my hotel and trade the savings from that into the market, I do not actually have any property rights that I can trade. I can only avoid some future cost.

*Response:* Smart consumers would ask for property rights when negotiating with a competitive supplier. But they tend to be the larger, more sophisticated buyers.

*Comment:* The implication here is that failure to consume generates a property right that is distinguished from not paying simply because you do not like the price. That kind of double counting is not quite fair. We want people to see the price signal and respond to the retail prices. We do not want to manufacture double rights that do not exist.

*Comment:* If I buy a sack of coal or a trailer load of logs to burn on a log fire, I actually have something to trade. With electricity, most consumers only have a variable volume contract and so have nothing to trade. If they are sophisticated, they may receive a short-term transmission right, but that would not

drive me into an energy management system that might be a three-year payback.

*Comment:* If we assume the consumers who are not being served through these competitive contracts are on a regulated rate, these rates would take into account the energy purchases and property rights. That is the cost of serving that load.

*Comment:* The average consumer never sees those prices. They do not have the market signals about the cost of their consumption. That is a regulatory decision.

*Comment:* That is bad retail rate design.

*Comment:* We have things that are unpriced, as well as things that are priced. Reactive constraint in New Zealand is an example of something that we do not price very well. In the western US where the market has not been set up and there are no RTOs, you might say that virtually everything is unpriced because you do not receive the right signals for much of anything. That makes it difficult to think about making merchant decisions in response to things that are already socialized. Someone, though, must deal with these problems and the investments in the category of unpriced. It seems to me it will be the character of the regulated transmission company, and therefore we need to have a better incentive mechanism and a process that helps them to describe the market so we can move them into the priced category. I think the theory of electricity restructuring is to favor the market. In other words, encourage people to spend their own money as opposed to having a central planner decide. If something is not lumpy, it is a merchant transmission investment and we let the market make the decision. If it does not, then we say that the market is probably making a better decision than we would.

*Response:* We are really talking about priced market value versus unpriced, not about big and small.

*Response:* Nebraska is a known constraint that today we ordinarily characterize as an economic constraint. But when we try to move energy that we rely on from North Dakota into Minnesota, that constraint impedes us and suddenly, it is a reliability constraint. As a transmission provider I know that will create a reliability issue more quickly or earlier than others. Therefore, how do you characterize such investments? Do you allow a merchant or a regulated transmission provider to come forward, even though today you see it as an economic issue?

*Response:* Draw the line at what we can identify as a separate, discrete project; call it economic if it meets the criteria. Be sure that the responsibility goes with the authority to act for those entities that are obligated to do so under regulated prudence requirements. Otherwise, you will put the regulated owner/operators or owners in a liability situation where they are unsure whether to act, or the RTO or market will. Make it a clear line.

*Response:* I want a clear line that is ex ante so there are no waiting periods.

*Response:* Reliability is the only clear line. Although a distinction between priced and unpriced is helpful, there are some other things, like the lumpiness of transmission. I am not sure that everything that we need to undertake will be a lumpy investment. Right now, we have imperfect information in both directions. On the other hand, the central operator does not have good information about contractual arrangements or strategic plans.

*Comment:* I think the difference between priced and unpriced, or economic and reliability-driven is very murky. But the question is if you have replaced it with anything more useful when you substitute

priced and lumpy versus priced and not lumpy. It would be better to formulate that distinction in a less judgmental way.

*Response:* In many cases the distinctions will be driven by the economic benefit that comes with it.

*Comment:* There could be a first-contingency violation five years from now, and if nothing happens, by default, it goes into a baseline plan. The standard that established that is unpriced. The likelihood of people responding is high, assuming it is priced in the marketplace. If a forecasted violation is priced or unpriced, I would still expect there would be some information discovery and that someone would eventually act if nothing is done. That sets the baseline for me.

*Question:* When a pool lacks a defined market at the onset, how can we determine the reliability standards in terms of deliverability? They may exist in MAPP or MAIN, but now we are expanding into a MISO market.

*Response:* They are different. Reliability criteria set by NERC will not change when you go to markets. Deliverability is a merchant product when you want to qualify for an extra market payment of a capacity resource.

*Question:* As new generation is added, it impairs reliability, thus requiring new transmission investment to meet NERC criteria. On an ex ante basis, can you define that market so that you can find where the free rider problem will exist and how you can cure it?

*Response:* If you want an adequacy requirement and you are merging things that do not have integrated deliverability, you have no choice but to go to a locational adequacy market. You then meet your reliability standards, but you will have no deliverability. The generators that have located in the wrong place will

be in a market where they have no value. You do not have to build to serve them; you just say, "By the way, we don't need you there and you don't get paid."

*Comment:* The deliverability standard then determines the reliability baseline.

*Response:* If you are reliable today and tomorrow you go to a combined system, you are still reliable. Assuming that all of your reliability councils are the same, you could then say you want a combined adequacy standard. Adding that standard will not make the previous system unreliable. It simply means that for your ancillary service – which is adequacy within a certain area – you will now recognize a locational requirement that presumably was also met if the system was adequate and there are no upgrades or transmission necessary unless you go to a larger footprint of deliverability.

*Response:* But you need to separate your energy market because it is the size of your coordinated dispatch. The next question is the size of your capacity market. You can start with your current NERC regions and then begin solving your seams problems. In the northeastern US, we are trying to coordinate capacity markets for New England, New York, PJM and PJM West.

*Comment:* There will be a lot of unpriced requirements if you want to have a single adequacy market and you start it separately. Alternatively you can meet the NERC reliability criteria, and to the extent that you want to have adequacy requirements, make them locational. If you do it the way New York does, you do not have to change anything. It will not cause problems, except that many generators would discover that had located in the wrong places. For example, the southeastern US has generators that thought they were meeting deliverability standards, but they are not. A lot of capacity there is really unusable. Prices

would be close to zero or negative if you had an LMP system.

*Question:* Where deliverability becomes an issue because of other people who build around an integrated system, how do you compensate the person who has suddenly had physical rights in a transmission system?

*Response:* You do not. The system is long, there is excess capacity and the prices are very low. If you were in a market paradigm, your bottled generation would be paid zero, in which case, it would have every incentive to build transmission.

*Comment:* The problem is that you have allowed someone to meet your adequacy requirement by being in an area where its value is zero.

*Comment:* In New York, generation used to locate in places where it was unneeded. Now it is locating where it is needed because New York has the right incentives.

*Comment:* The vast bulk of the generation that was built in Maine and in some areas of the Midwest does not have firm rights now. Most of them built almost simultaneously based on the free rider issue.

*Comment:* The only solution ex post is to go to locational adequacy markets, unless you are willing to tax all kinds of people.

*Question:* How do you convince the regulators that this was a good move without first building the transmission, when people will be calling them up because of the congestion they have to pay?

*Response:* Because the people on the other side will be paying zero for their energy.

*Comment:* The longer you wait, the more trouble you have because your generation

will continue to site in the wrong places. At some point, you have to get started.

*Comment:* In PJM we heard that there was too much congestion, or not enough transmission. Lo and behold, once the price signals were in, generation began showing up in the right places. In the last few years, merchant transmission proposals have shown up, not within, but between different markets. We began to figure out the necessary connection services, and the rights for providing those services. FERC's economic upgrade order certainly has created a firestorm of controversy and comment. Yet when you step back, the fact is that PJM did not really get around to defining the property rights that go with merchant transmission AC until now. There is no merchant transmission because you never had the things in place for someone to evaluate whether or not they could do them. I am not sure if congestion is as big a problem economically as people say it is. In PJM roughly a quarter of it was due to outages occasioned by connecting new generation that was coming online; some was due to routine maintenance; and maybe another quarter was due to ice storms or solar magnetic flares. What does unhedgeable mean when it is only one quarter of the congestion? If it is not that big, there is no pressing economic need to address it quickly and get it wrong. We probably ought to hash things out and get it right. I believe that when markets take root in other parts of the US, you will see generators locating in the right places and market-driven investment will occur.

*Comment:* The notion of unhedgeable troubles me because everyone is served in a reliable system. You can hedge against resources when the system is being redispatched because transfer from cheaper resources is unavailable. There are also field hedges, and contractual hedges against the local generation.



*Question:* If many of the new investments in transmission are deepening in nature, where you try to co-locate new facilities on existing sites, some would argue that it may be better that the existing transmission owners do those investments because of the complications involved in contracting with the merchant.

*Response:* It is a bogus argument. I do not have a problem with having the existing transmission owner building it. Operation is through the ISO, so there should not be a problem of coordination. There are generation upgrades all the time where the generator pays for the upgrade and it is integrated into the system. The generator receives the property right and pays for the maintenance as necessary. The ISO directs the operation and negotiates the interconnection agreement. If you tell FERC you will not allow someone to interconnect and not build the upgrades, I think FERC would tell the TO that it will not work that way.

*Response:* We should be clear about which pieces are financing vehicles and which are operational issues. TOs already lease space on poles and towers; they know how to work with others.

*Response:* As long as this is laid out ex ante, it can be made to work. As in independent company, I am disturbed when we are pushed back into a corner as the backstop. We cannot financially plan for the future around that.

*Comment:* I think a lot of this is a change management issue. No one will be able to put in an optimum system overnight because you will lose some entitlements and some free riders. Some people will be hurt. You do need to figure out where you would like to be optimally and then discuss how long it will take and the number of steps. Next, figure out how much you are willing to invest over time to go to this more perfect system. If we spend too much time focusing on what it

takes to get to the perfect, we will never get to the good. Aim toward the perfect and just take better and better steps.

*Comment:* I think we can give MISO three or four years during which it can operate under an LMP market without charging anyone. The price signals will be sent, giving people comfort, rather than the first time someone has to pay for congestion, the calls go to the governor and there are lots of problems. Realistically, we have fallen back toward deregulation at the wholesale level. We need to make people comfortable again that this can work.

*Comment:* Spending all this time trying to make things perfect keeps us from going where we need to go. When PJM was being formed, I remember someone finally said, "Look, I don't care what rules you make. Just give me some to deal with and I'll figure out how to work within them."

*Comment:* I think a little bit of regulatory fortitude needs to go along with this because there are market efficiencies that you will not capture until you actually move and pay and settle on these issues. Just looking at congested prices is not the whole story.

*Comment:* The lost opportunities are not visible to the regulators today.