

**Harvard Electricity Policy Group
Forty-Fourth Plenary Session**

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RAPPORTEUR'S SUMMARY*

Session One.

Transmission and Generation Planning:

What Is To Be Done? Who Needs It? Who Does It?

Who Pays For It? Who Regulates It?

Despite the emergence of competitive markets, central planning has never entirely disappeared from the electric sector. In transmission, the need for planning in some fashion was always generally acknowledged. In terms of generation, however, many advocates of competition came to see planning as a vestige of an earlier age. Even those who were not prepared to abandon the need for central planning entirely saw it in far more limited terms than required for complete integrated-resource, least-cost planning.

In today's debate, planning is making a comeback. The problem is that the industry context and market structure is so different that it is unclear what planning actually means, who will actually do it, how it is paid for, and who provides regulatory oversight. How can we be assured that the planning process will not skew the competitive balance in the market, particularly in regions without RTOs?

Whose needs have to be taken into consideration in the planning process? Will the planning be indicative only, or will it be determinative? If the latter, how will plans be enforced, and on whom (e.g. LSEs, Generators or RTOs)? Who will actually carry out the planning (e.g. PUCs, RTOs, Reliability Organizations, Regional Bodies, FERC or Transmission Owners/Providers)? What planning criteria are to be employed? How will cost recovery be handled? Will such planning automatically imply regulatory pre-approval and cost socialization? Will planning be limited to assuring reliability or will it include resource selection and other matters? How will planning be coordinated, if at all, with the siting and certification processes of the various states? What type of planning, if any, is compatible with competitive markets for energy? Are end users bound by the planning process or can they opt out?

Speaker 1.

It is hard to rationalize the idea of planning with the idea of a competitive market. The industry doesn't do much centralized planning in gas

exploration, oil refining, or other aspects of energy industry. However, transmission planning remained even during the height of the movement toward restructured markets. It is done at the utility and the regional reliability

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

council level in traditional markets. Further, it was a selling point for commissions considering whether to allow their utilities to enter RTO [regional transmission organization] markets. In PJM, their planning process forces utilities to do some things that a state commission probably couldn't do itself, given its territorial jurisdiction. Certainly, the planning process in RTOs has not reached a state of nirvana.

A number of factors demonstrate a resurgent interest in transmission planning. First is a perception that existing transmission infrastructure is inadequate. There's a sense that LMP [locational marginal pricing] based price signals haven't been sufficient to procure the construction of new facilities. Some argue that some vertically integrated utilities have been deliberately failing to construct new facilities. This is done to favor their own generation.

The resurgence is seen most clearly in some of the new proposals that FERC has pending. In FERC's view, the reason we don't have adequate infrastructure is that it's not being planned for adequately, both in RTO and non-RTO markets.

Generation planning is another issue. Before serious restructuring efforts in the 1990s, there was a lot of state level planning. Most states had integrated resource planning [IRP]. This was a costly, complex, and contentious process that pitted different interests against each other in hearings that lasted as long as two weeks. The planning process in generation was fairly cumbersome. IRP was bypassed as restructuring was implemented. Even non-restructured states like North Carolina phased back their IRP activities. That's due in part to adequate base load generation and relatively low input prices. If utilities were going to be allowed to move in a competitive direction they didn't need to have every move looked at in an IRP case.

However, the worm has turned again. There's been a resurgence of interest in traditional IRP, particularly in the non-restructured areas. Recent cases have been strongly contested by environmentalists over planning issues for the

first time in close to a decade. That's only a harbinger of things to come. New base load plant construction will involve a sharp rise in the cost of fuels combined with increasing concerns for the environmental impact of electric generation due to climate change, mercury, emissions, etc. In the non-RTO world, integrated resource planning is back.

There's also a resurgence of planning for generation in restructured markets as well. For instance, some argue that capacity market proposals are an attempt to ensure LSE's [load serving entities] have adequate future generation. It's not IRP but it is a form of generation planning. All the functioning RTOs, except MISO, now have a capacity market construct or are attempting to put one in. This reflects a resurgence of interest in generation.

Do we need to be concerned about planning and its potential impact on competitive markets? I would say no. Half the country never followed through with competition. Second, the planning proposals are meant to make markets work better, not worse. Both FERC and the stakeholders pursuing them have this goal in mind. Finally, the effort reflects a desire to fix perceived deficiencies in markets.

The real question is whether we do it, but how we do it right. There are several issues to confront. First, make it as open and as collaborative as possible. Some states have tried to get utilities to broaden their perspective when they look at these planning issues. North Carolina now includes all the load serving entities in the state for planning. Previously, planning was inconsistent. Worrying about planning for reliability or economic purposes is ineffectual. Most facilities have dual purposes. A facility will have some reliability benefits and some economic benefits. Some commissions have successfully resolved cost allocation issues by incorporating this idea.

The problem of resource choice, particularly in restructured markets, needs to be solved. Which resource to use given that needs can be addressed with transmission, generation,

efficiency programs or demand response. Coordinating these planning efforts has benefit, folks are working on that. None of this planning is useful without addressing cost allocation questions, particularly for transmission.

A beneficiary pays approach shows the most promise for cost allocation. Cost assignment should be recalibrated on a regular basis to take changing market conditions into account. Stakeholders need to accept that there is some inexactitude in cost allocation. Past experience in the 1980s showed it's sometimes a question without an answer. There are imperfections in all the plans.

Nonetheless, resolving cost allocation has to come before the transmission planning. The resurgence of planning is real, it's beneficial, and there are obstacles to its successful implementation that require serious thought.

Speaker 2.

I'm interested in something I call "True Joint Transmission Planning." We need it now more than ever. Generally, reliability transmission improvements needed to avoid near-term NERC criteria violations are mandated, and then the market or specific participants build or fund the rest. I'm hopeful this approach will end soon.

The legacy of these policies are critical congestion problems from New York to Northern Virginia. Another legacy is endless litigation at the FERC. There's a huge slew of dockets on the commission's agenda. There has to be a better way.

In recent filings, PJM summarized the recent evolution of their transmission planning process. In 2002, they standardized interconnections for new generators. In 2003, they standardized interconnection of independent merchant transmission projects. There haven't been many of those. In 2003 and 2004, they implemented procedures for "economic planning." This process for economic planning was never going to get economic additions built and that has been

the case. Various filings at FERC demonstrate the disappointing success PJM had with that process. In 2005, they incorporated a 15 year planning horizon. This is a great positive step. In 2006, they will integrate long term market efficiency studies into the planning process.

At a FERC technical conference in April 2005, Audrey Zibelman stated, "Today, rather than having the policy of a strong transmission grid, we effectively have a minimalist transmission policy, where transmission almost becomes in most regions of the country an antecedent to generation, and is just largely built to help move local generation to local load. ... we really have a transmission system on life support as opposed to that robust system that we want."

The real question is how to get transmission off life support. We have to acknowledge that the market will not solve this problem. While transmission is not federally financed like the interstate highway system, it is effected with the public interest. It's necessary to all of us, it's difficult and expensive to get built. The idea of duplicating it to have competing networks is strange, most regions are lucky to get one built much less two. Further, today's economic upgrade may well be tomorrow's reliability upgrade. This artificial distinction keeps us behind the curve.

Why can't we all just get along? We need those serving loads in a region and those supplying power to cooperate on building transmission infrastructure that they all need to conduct business. Consumers would be better served as well.

I'd like to discuss one promising proposal called the Cap X 20/20 project. It's like a barn raising on the prairie because it involves Little House on the Prairie country. It covers Minnesota, South and North Dakota, Iowa and Wisconsin. It has 11 investor-owned municipal and coop participants. They're highly interconnected and have common needs. MISO's shorter transmission planning process horizon did not account for their long term needs. Moreover, some of them are in MISO, and some aren't.

They got together and forecasted customer needs, their projected load growth, to the year 2020. Then they conducted a “nondenominational” open access study to determine what facilities would be needed for regional reliability until 2020. They focused on higher voltage transmission facilities common to many generation supply scenarios. Instead of assuming they were going to build all the generation they ran different scenarios which included different sources like wind and a variety of different generation locations. They found out that certain facilities were common in all those scenarios.

These common facilities were called the group one projects agreed that they should be built. There’s four 345 KV lines estimated at \$1.3 billion. Then the full collection of all the utilities in Minnesota, the munis, the coops, IOUs, went to the Minnesota legislature together and said these are the projects we need to get in regulation, cost recovery, and siting. They got it through the legislature, and will be filing the certificate of need with the Minnesota commission soon. The utilities will jointly own these facilities.

The model is attractive for several reasons. First, all load serving needs are considered. The IOU who owns the line, a coop, or a muni; all loads are considered on the same basis. The joint ownership feature by the load serving entities that use the system is innovative. The consideration of multiple generation scenarios was helpful. They worked together instead of litigating and insured a reliable substantial grid in years to come. They came out ahead of the curve for once instead of having to add another reliability band-aid.

Joint ownership of transmission is useful. Many public power operators currently own a pro-rata share or specific pieces of a transmission system used to serve their loads. Examples are Georgia, Indiana, Vermont, Wisconsin, Arizona. These operator’s consistently report that it’s better to own than to rent. There’s less litigation at FERC, there’s a more collegial relationship, and there’s a seat at the table when you plan

transmission. The American Public Power Association recently passed a resolution supporting joint ownership. It’s a useful process for resolving many of these planning problems.

Speaker 3.

Much of what the previous speaker discussed has occurred in Wisconsin, the upper peninsula of Michigan, and a bit of Minnesota. Many of the same utilities involved in Cap X tried to set up a company called Translink which had a similar planning model. Audrey Zibelman was a key player there too. She took that upper Midwest wisdom and is trying to insert it into the eastern marketplace.

I’m going to discuss ATC, a large transmission company active in Wisconsin. They run their own facilities in four states down to 50 KV including radio facilities. Since 2001 they have constructed or rebuilt nearly \$1 billion worth of transmission. This year they are investing \$400 million in capital and have the same budget for next year. Their ten year plan calls for additional expenditures of over \$3 billion of transmission. Rather than having jointly owned facilities, the company is jointly owned and then one company runs the facilities. They are owned by all their customers including many public and cooperative entities in the state. Public power owns over 10% of the American Transmission Company.

ATC owns, plans, builds, maintains, and operates the transmission facilities. They are a member of MISO. ATC was active in the creation of MISO. The goal there was to make planning effective, not just to create a regional planner. They specifically designed planning that did not have a strong centralized planning function. It is a bottoms up, top down planning approach. This comes from the belief that all transmission is local, particularly in a large region like MISO. State commissions need to be involved in the process and this is more difficult in a regional setting than within one state. Their customers are strictly the load serving entities, the LDCs [local distribution companies]. They

do not serve retail load directly, even in Michigan and Illinois which have retail access. The Arrowhead western line runs from the top corner of Minnesota into Wisconsin. It's a 220 mile, 345 KV project that will cost around 420 million. It is being built because ATC repeatedly demonstrated that the line served local need. Opponents said they were building it to allow the regional marketplace to work and that power was just going to be shipped through Wisconsin. They argued it was simply a pass-through from Manitoba to Chicago. ATC demonstrated that the line served regional purposes but that it primarily served local need. Transmission won't be built if people whose yards it's going through aren't getting some benefit.

Another project in Wausau just got approval for 100 miles of new right-of-way 345 KV line. This \$250-300 million project had no organized opposition because they spent so much time working with the local communities. They were able to effectively identify issues that people had and resolve them. This made commission approval easy.

They are able to justify facilities based on market access too. They identified a line in the southern part of the state which will be justified strictly via market access and congestion reduction into service territories. This will still have to receive Wisconsin commission approval. The state will decide based on the congestion, the market costs versus the imposition of an additional transmission line. This is an appropriate policy decision.

They have also interconnected over 2,000 megawatts of new generation in their six year history. This underscores the fact that transmission is not a market participant. It's an enabler of the market. It facilitates the load having access to generation and allows the generation access to the load. There are some instances where transmission can be viewed as a substitute for generation and load but this is rare. ATC works to ensure they don't over build transmission, though this is somewhat counterintuitive given how difficult it is to get things built.

Wisconsin has set an 18% reserve margin for planning purposes. When there is enough transmission built they're going to lower that to 12-15% because of increased reliability from the access to power outside the states. There's a real savings to Wisconsin and the upper peninsula of Michigan if more transmission is built. It's not a substitute for generation. Their belief is that all customers and load serving entities benefit over the long run from a stronger, less congested transmission network.

They're seeing more interest in integrated resource planning as well. Planning at ITC reflects accountability for reliability of service to the local load serving entities, for adequate market access. They do interconnection studies and the TSRs [transmission service relief requests]. Those are delegated from MISO but they insisted with MISO that they continue those studies. One can't just study one need in isolation of what's going on in the rest of the system. Finally, they will be accountable for the new NERC planning guidelines.

ATC has had a ten year plan since they started. PJM is going to a 15 year. They may go a little longer in the future. They have a staff of 35 planners who are regularly reviewing the process. It's a transparent, collaborative process. They have regular meetings with all stakeholders and discuss plans at a high level of detail; every single thing down to the breakers. Basically they'll present the plans in detail and ask if it makes sense. If it doesn't, they look for feedback.

They cannot plan for load on their own. They have to plan long enough in advance and work with generators and the load. It always takes longer to build transmission than it does to build generation or implement effective energy conservation programs. The long term plan gives a strong signal that allows stakeholders to account for alternatives.

There's a strong public input into their routing and siting. Beyond identifying the need, they actively reach out to communities before a final decision on route or site is made. They lay out

alternatives and get input from local communities because they understand which areas have environmental, historical, or residential sensitivities. Some people want lines along highways, and other communities don't. ATC takes a stance of "they can tell us where it should be built and then we'll build it." By having that flexibility, going to communities three different times in the planning process and getting input, communities either can't or won't oppose it because they've helped design the facility.

Even in areas like Dane County near Madison with an activist community, they've had success. It's a fast growing area with minimal generation and inadequate transmission; they need something. They're not going to build generation, the city and the county have already said that. It's an activist community and there has been a lot of energy conservation and load response. However, they are growing at 4-5% a year and need something more. ATC put together a collaborative two years ago, paid for interveners to participate, and this resulted in a study that demonstrated a need for new there. There was no agreement on how to meet that need but that first hurdle was successfully resolved. They're in the process of designing an agreement on where and how that need should be met.

Given the activity of ATC, what's the role of the RTO [MISO] and why did they spend so much time getting MISO up and running? There is an important regional role to play. Local needs, political realities and priorities, the ability to assess constructability, cannot be done at a regional level. You really need to know the area in which you're working. ATC also works with other service territories like ComEd who are not in MISO on a regular basis. They just jointly got a facility built that significantly improved import capability into Wisconsin. The line is almost all in the ComEd service territory. They plan with their neighbors without the RTO. The RTO is not necessary for collaboration with the neighbors. Cap X 2020 created their collaboration without MISO.

The RTO is necessary for regional needs, particularly as you develop a market. There are some interesting changes in market flow because of centralized dispatch in the market. Having the RTO set up the market is needed because no one transmission owner or group of transmission owners has a big enough concept of the market. The RTO does this. It provides a context for regional cooperation. They facilitate the dialogue, provide broader scale models and technical support that let transmission owners do their job.

Wisconsin has a strong state commission and long history. However, FERC is looking at planning because needed facilities aren't being built; planning has been inadequate. Wisconsin had a 25 year history of doing 20 year transmission planning but nothing ever got built. Planning is a necessary but not sufficient condition for getting things built. Long, involved, detailed planning processes can just as easily stop anything from being built. Creating a process that works collaboratively to plan the transmission that's needed is critical. The state can facilitate generation additions require additional energy efficiency as needed.

I'm not a fan of federal backstop authority. ATC has worked to ensure none of their areas are declared corridors of national interest. The cooperation of the states is critical to get things built. You can't override that need and necessity by going to the federal government. It is truly a last resort.

Finally, ATC is working to be more obvious about the cost of new transmission facilities. Then generators and local load can assess whether generation or load reduction can substitute for the transmission facility. Some of these lines take five to seven years at minimum. Arrowhead Western has been in the planning phase since the mid 1980s and it's going to go into service in 2008. Planning needs to involve public input, be transparent and collaborative. The idea of spreading transmission grid costs over a large area is a problem. ATC doesn't want the commission of Ohio saying they don't want to pay for part of a line because they get no

benefit. ATC is able to figure out amongst themselves who pays for it. They will continue to do that. The notion of a regional postage stamp seems problematic, but that's something that FERC will have to decide.

Speaker 4.

I'm going to present a case study of transmission planning in the Entergy footprint from a merchant perspective. A lot of the merchants have gone belly up in the Entergy region or changed ownership. There are large plants in this area, the largest having an output of about 2200 megawatts. There has been lots of churn in ownership and spin-offs. Large banks and hedge funds have been the principle owners.

Entergy evolved from five operating companies. The individual operating companies were originally designed so their load could meet their generation. That's how the transmission system was originally designed. In the 1960s a 500 KV backbone was added to the system and the system is still in this original configuration now. Entergy Arkansas serves most of Arkansas. Entergy Mississippi serves the west side Mississippi. In southern and northeast Louisiana, you have Entergy Louisiana. ENO, which is Entergy New Orleans, serves the city of New Orleans. Finally, Entergy Gulf States serve a portion of east Texas which is in the eastern interconnect, not connected to ERCOT. They also serve a southwestern portion of Louisiana.

The five operating companies are dispatched as a single system and share a single transmission tariff. Transmission planning is performed jointly although projects are assigned to individual operating companies. They are regulated by state commissions, the city of New Orleans regulates ENO, and FERC has jurisdiction over all of them.

This system is grossly over-built. The NERC summer assessment for 2006 showed a 53% capacity margin, including unsubscribed merchant generation. There is over 14,000 megawatts of unsubscribed merchant gas

generation with effective heat rates in the 6900 to 7300 range; modern efficient technology. Entergy also has over 15,000 megawatts of utility owned gas generation that is older and less efficient with heat rates exceeding 11,000 BTUs per KWH. There are two major and one minor load pockets in this region. Entergy, through a number of studies, has identified six generation plants as RMR [reliability must run].

There's two major issues for transmission here. First is RMR. These requirements are driven by two needs. Transfer limitations, moving power from one region within Entergy to another, involves problems with line overloads and thermal limits. Second are voltage requirements; local generation within load pockets that provide reactive power to maintain system voltage.

The second issue is transmission bottlenecks. These show up all over the footprint. They change daily, there's hundreds of them and many of them have been revealed by merchant generators. They generally appear at the lower voltage levels. A 500 or 230 line goes down and a variety of lower voltage lines overload. There are a lot of these flow gates or bottlenecks on the system.

Entergy has a standard planning criteria that is not at all unusual. They have NERC reliability standards, SERC, and their own set of guidelines. There are two of their guidelines that are worth mentioning. The first is minimizing the use of generators for reactive power. Second is their criteria that they provide 100% of their own reactive requirements. That's unusual because merchant plants can provide reactive power too.

The planning process is done by the transmission business unit of Entergy, TBU. They develop a two year construction program with a five year planning horizon. At the end of the process they hold a transmission summit and present the results to stakeholders. There's no collaboration prior to the summit. The models used to determine transmission service only include projects in the two year plan that have been approved for funding.

Their traditional planning structure looks appropriate, they have all the right criteria, but it breaks down at a more detailed level. Their stated objective is to facilitate the reliable delivery of energy from designated resources to native load. In this process, Entergy Services commercial operations provide the transmission folks with the designated resources and the load forecast. The transmission folks put those in their model. They have sales and purchase information and use their designated generation resources to meet the load. The process makes it appear that the interests of the ratepayers are taken into account.

However, the designated network resources are primarily utility owned generation and long term purchases. Entergy has few of those. This includes inefficient generation at system capacity. This system capacity is dispatched in the model. There's no requirement to forecast RMR requirements, evaluate RMR mitigation strategies, address overloads in the short term models, or consider the economics of the dispatch or the prevailing economics in the market.

The bulk of the RMR generation exists near New Orleans, southern Louisiana and a pocket around Jackson, Mississippi. The bulk of the unsubscribed merchant generation is in the unconstrained region: northern Louisiana, Arkansas and Mississippi. The transmission limitations ensure that the large amount of merchant generation located outside of the load pockets is unable to displace this more expensive, less efficient generation.

This situation has occurred for several reasons. First, the designation of network resources. Inefficient gas generation makes up 60% of Entergy's installed capacity. In 2005, 30% of Entergy's energy needs were met by third party purchases. Of that 30%, 65% were short term and not represented in the models as network resources. There is a disconnect between capacity versus energy on the system. The energy is actually used to meet load.

At least 65%, or about 24,000 gigawatt hours, of the third party purchase power is short term power that displaces the network resources on the system. Entergy only considers the deliverability of network resources in maintaining and upgrading the transmission system, and short term power is not considered a "network resource." The transmission system is not maintained or optimized to facilitate purchase power opportunities. It's maintained to insure that inefficient utility owned gas generation can serve future load needs. Worse, and this has occurred, transmission upgrades can negatively impact the deliverability of merchant generation because they're not considered in the planning process.

In the planning process the model flows reflect patterns that are not likely to dispatch in real time. They do not represent historical patterns or expected future patterns. Thus, merchant generators who look out from one to six months only see operating constraints. They can be constrained in one, two, or ten directions. Most of these constraints don't show up in the operating horizon and don't show up in real time. This is because the dispatch in the models is not the same dispatch that occurs in reality. The merchants have coined these as "phantom type" constraints.

The real constraints on the system tend to show up daily or hourly. In 2003, Entergy issued two TLR [transmission load relief] actions in the month of July. In 2004 it went up to 200, in 2005 it dropped back down to 79 and in 2006 there were 626 in one month. This occurred because a lot of power was going from south to north out of Entergy's system which is unusual. Typically not the entire schedule is cut. There's a pro-rata approach that's described in the transmission tariff.

The second issue concerns overloads. When Entergy runs their planning models they recognize that some overloads are not real. They understand that closer to delivery, different generation resources will be dispatched and displace their own resources. They recognize it but they don't address some of these overloads.

They let them stay in the planning models that are used on their oasis system to grant transmission service. For merchant generators this means that all requests for transmission service are denied because the need doesn't show up in the planning model. This occurs even though the facility that's limiting them is already overloaded.

The TLR actions presumably have a cost to them. If an operator is cutting a schedule, the replacement is usually less economic. This affects ratepayers. Further, the transmission volatility has a negative impact on the development of a wholesale market. Generally traders can mitigate a reasonable amount of risk. However, in this system the problems change and/or multiply on a month to month basis; it's very random and has a severe impact on forward deals.

The RMR requirement is the last problem. The internally developed transmission plans do not address reduction of RMR generation. There is not much, if any, collaboration with regulators in the transmission planning. There's no forecast of expected generation and no mitigation to lower RMR generation. In other regions, both RTO and non-RTO like Arizona, regulators have utilities produce detailed studies of RMR requirements which are used for the planning process.

In Arizona, the Phoenix valley is a huge load. It's growing at 500 megawatts a year. There's 7,000 megawatts within the valley and a lot of the generation outside the valley. They've worked to reduce the use of inefficient generation within the Phoenix load center. This RMR generation is used to manage line loading relief and local voltage problems. There are still six plants RMR plants but those units had an effective heat rate exceeding 11,000.

Back in the southeast, Entergy's energy resources are a mix of base load, their nukes, some hydro and coal, their RMR energy is 12%, and their purchases are a significant 30%. They have two new combined cycle plants bought from merchants that went bankrupt. There is

also non-RMR gas fired generation outside of load pockets. Heat rates vary from 7 to 11 thousand BTU; These represent significant cost differences with today's gas prices.

In 2005 the average weighted heat rate of merchants in the Entergy region was about 9.3 for 2005. The average weighted heat rate of the utility owned gas generation was about 11.6. The average price for gas was about \$8. This resulted in a difference of about \$18 a megawatt hour. The utility owned gas generation generated about 23,000 gigawatt hours. If even half of that is displaced, that is over \$200 million. The numbers are significant and mitigating the use of these resources should be an objective.

These resources have been in the Entergy footprint for four or five years. These problems are going to exist for a while. There are no quick transmission upgrades. The cost benefit analysis of the alternatives is unknown and the use of the inefficient RMR generation will be at ratepayer expense.

Given the past description, are the interests of the ratepayers and the IOUs properly aligned in today's environment? Whose needs have been considered in the planning process and why aren't stakeholders involved? A deficient planning process can skew the market's competitive balance? The proper planning criteria must be employed. In a regulated environment, planning should assure reliability and include resource optimization? Regulators should be willing to consider approval of transmission projects for rate base treatment to open up markets. Who's going to pay for it is always a question, as is the degree of regulatory oversight.

A Baton Rouge newspaper showed that four of the five operating companies for Entergy are on the top ten list for the highest residential electric bills. The ratepayers need to be considered in this transmission planning process.

Comment: All those companies are in the south and we always thought they had low rates. That

list reflects the extensive use of air conditioning in the south rather than poor transmission planning. The list reflects electricity bills, not rates.

Question: My question concerns the Entergy region. How did anyone finance a merchant generation project in that setting? Has anyone sued the due diligence consultant?

Speaker 4: A project would not get financed today. finance a project today. The Union and Gila Entegra projects are financed or cross collateralized in the context of the 2000 environment and market studies done then. This was prior to the Enron issues and the California debacle. The markets were opening up. The market studies showed that inefficient generation would be displaced by the more efficient generation.

Speaker: Generators should hire transmission engineers. Developers don't necessarily have the transmission expertise, especially in non RTO regions, to evaluate deliverability. In a different context, a developer thought they had executed a deliverable contract with a utility, assuming that they were in PJM. They weren't even aware that the utility wasn't a PJM member. They just assumed.

Speaker: That's an example of bad grid analysis. Marketing consultants coming in and indicating where transmission lines crosses wires. They simply say that this would be a good place for a plant and that was the end of the grid analysis.

Question: Many companies have been developing comments for the OATT [open access transmission tariff] NOPR. What is the legitimate place of capacity benefit margin in planning? It's not discussed in the context of operating criteria or day-to-day operating. Does it have a place in a planning context? If so, how should it be utilized?

Speaker 2: FERC has proposed three different possible approaches to CBM [capacity benefit margin]. This includes improving the definition, or ending its use. CBM does have a legitimate

role for maintaining reliability. However, way it has been calculated and the secrecy surrounding it is the source of frustration and suspicion. NERC should better define when it should be used, and who has access to it. Many LSEs would like access to CBM to protect their load serving capability in the service territory.

Question: Just to clarify, do you see a role for it in planning or is there a legitimate role for it in reliability in an operating context?

Speaker 2: There's a role for it in both. Whatever the planning assumptions are should be reflected in the operating assumption. That's one of the problems that were demonstrated in the Entergy presentation. Our top level electrical engineers believe that you have to translate the planning assumptions into the real time operating environment, otherwise a lot of shenanigans can take place.

Question: Since the transmission system was strengthened in Wisconsin, their commission is considering dropping the reserve requirement. That sounds similar to CBM.

Speaker 3: Yes. ATC is attempting to be transparent about its use. There's an agreement with customers that some actors have access under emergency situations. It's not used from a planning perspective. It's most important that NERC come up with a transparent way to identify how it's calculated and used.

Question: In the Cap X 2020 the states are in the less densely populated areas of the country. Can that model work in densely populated areas?

Second, one speaker suggested that individual states should determine the transmission alignment state by state. Does that sacrifice efficiencies which translate to higher cost?

Speaker 2: It's easier to build and site transmission in North Dakota than it is in New Jersey [laughter]. However, Cap X is a model of collaboration, of consideration of everybody's needs, of considerations of many different generation scenarios. This makes it easier to be

built. Consider what happened in the Minnesota legislature. It's very rare that munis, coops, and IOUs all show up together and say we need this. It may not be enough to get transmission built. Having a unifying factor definitely improves the odds.

Transmission is difficult, expensive, and nobody wants it anywhere near them. It's so important to have collaborative efforts and to do the ground work necessary. If it's one IOU coming in they are accused of gold plating their transmission facilities. It's better to have a chorus than it is a soloist.

Speaker 3: Wisconsin does have major metropolitan areas. Milwaukee has a metropolitan population of 1.5 million. Madison is an urban area. Arrowhead Western went through all rural areas, and yet it was contested throughout the process.

These models can work in both urban and rural areas but you need to differentiate who the audience is, and what their needs and concerns might be. Planning state by state leads to inefficiencies if that's all you do. The transmission operator should regularly visit neighboring state commissions. If they need facilities that will cross state lines then all commissions should be involved simultaneously. MISO or another RTO can facilitate the discussion as a neutral arbitrator and provider of expert analysis.

Question: I'm concerned there's something missing from the presentations. My question requires a preface. First I was alarmed that transmission is being characterized as an enabler and that it's not competitive with generation. This was clarified as transmission being different from generation and that the transmission operator could publish transmission plans and generators could decide if they could substitute for it. Clearly they do compete and there's an interaction between the two.

There was a discussion of the history of IRP which is relevant to this discussion. The complexity and cumbersomeness of IRP is not

good but some of these other processes are similar. There are two other factors to consider in these processes. First, they inherently become politically correct processes. The objectives get distorted by that political process and the final choices will not be robust or have bad outcomes. Planning processes get distorted and the process in Entergy is an excellent example. The attraction of markets was to find another way to deal with that with better incentives and alternatives.

A key question that wasn't answered is whether the planning is indicative or determinative? If planning is only indicative then there's little problem. Indicative planning shows that transmission should be better, information can go on the web, everybody can see what it is, etc. When planning is mandated or determinative and people will pay under rate base, spread costs, or beneficiary costs, it's a problem

Second, these processes get characterized as all or nothing. Either the market isn't doing it so we'll have a central planning process that is determinative. Or alternately, LMP will solve the problems and the market will address transmission adequacy. I think that most people characterize one of the two extremes but the real solutions are some place in the middle. If this is so, we haven't defined clearly how things are going to work. Which aspects are market oriented and which are mandated? Where is the boundary?

Speaker 1: Did earlier processes produce a good result? No. Have markets produced it today? No. With respect to the question of indicative versus determinative the answer depends on the context. If transmission or generation facilities are part of an integrated resource plan in North Carolina, the commission has the authority to order the construction of facilities. In that context the plan can be determinative.

At the RTO level planning can become determinative in some circumstances. What is the role for markets? I don't really know. Like any other regulatory process there is a danger they may go askew. Regulation can be done well

or poorly, integrated resource planning is no different. The resurgence of interest in integrated resource planning in North Carolina came from a renewed engagement by the environmental community. There are concerns for who participates and gets heard.

One of the challenges in the traditionally regulated world is how they integrate the availability of different market options in planning and rate making. It is still unresolved.

Speaker 3: It seems as though you are asking whether RTO planning is indicative or determinative. It can't be determinative because the RTO doesn't grant the authority to have a facility built. They may have a requirement to try to get it built. That occurs in the MISO transmission owners agreement. If there's a facility in the plan, the transmission owner is obligated to go to the regulatory authority for approval. That may make it determinative, I'm not sure. To me, it's the state commission who has the ability to make it determinative. A transmission owner or RTO can only recommend.

Speaker 1: If a utility comes before a commission and files an application to construct a transmission facility because an RTO's planning process indicates it's needed, that carries considerable weight. It's not conclusive for a commission but very influential.

Speaker 3: It's important, but no Midwest state is willing to grant MISO the ability to declare a facility needed without their own state processes.

Speaker 1: No state is bound by it, but regulators will not dismiss it out of hand. They will pay attention to it.

Speaker 2: I have some random observations. Some have argued that under a market model developers can propose and take the risk for transmission facilities. In April 2005 at the FERC hearings a representative from TransEnergy said that merchant transmission facilities need a long term contract backed by

the rate payers. In this case it was LIPA [Long Island Power Authority]. Even in this merchant transmission case, it required public power with an obligation to serve and the ability to sign a long term contract to support it. Somebody's rate payer is paying for it under a planned or a market model. Wall Street will not lend money without assurances for transmission facilities.

The answer to your question is joint ownership. Transmission planning should show that we don't always need transmission. Other options should certainly include generation and demand response. Generation is not a full substitute for transmission. If one drops a single plant in a load pocket, then there's one more plant that enjoys market power. If transmission is built into the load pocket then none of the generators enjoy market power. That is a better outcome for consumers than one more generating plant needed to relieve NERC criteria for the next three or four years. They are not full substitutes, but they should be considered.

The market experiment has had significant time and transmission development has lagged because of it. It's both Entergy and PJM that are behind the eight ball. In PJM, the AEP, Allegheny, and PEPCO proposals should have been implemented six years ago. They've lost time.

Question: There are three ways to address the problems in the regulated Entergy model. The first is to create a regional transmission organization that looks at issues neutrally and makes system operation recommendations. The second is a pricing mechanism like LMP that makes things more transparent. The third is a planning model that sorts through issues via an up front planning process.

Some are critical of the costs associated with RTOs and very concerned about the success of LMP. However, assuming that the problems inherent in the Entergy model are correct, then how do the issues get sorted out by regulators or by a group of LSEs who depend on the system?

Speaker 1: North Carolina's Commission has reached out to municipalities and cooperatives to determine what they really wanted. They had been initially attracted by the day two RTO model, but they realized that costs and risks would be high. They concluded they needed a transmission system that accounted for their needs as well as the vertically integrated utilities. In North Carolina the transmission is owned by the IOUs and the munis and coops are dependent.

Once everyone realized that the munis and coops didn't want to go to war with the IOUs, the Commission began to develop a planning process for North Carolina. There are questions about whether it could be expanded into other states. The Commission has certainly encouraged it. Historically these groups have not talked to each other and they are now. A lot of misinformation and apprehension has dissipated. Those stakeholders are beginning to talk seriously about a plan. Cost allocation hasn't been addressed yet. That will be a big issue.

Although progress has been made, the jury is still out on that process. There are some assumptions and issues that have emerged that surprised people at the Commission. Their overall response is to put together a planning model.

Speaker 2: The Cap X proposal is one example of the planning model approach. RTOs will not be formed in areas of the country that don't have them. Some current RTO members have become slightly disillusioned with that model. The Cap X model does not require an RTO but only requires a comprehensive assessment of everyone's needs. The situation in Entergy sounds dysfunctional. It's a grossly inefficient network and a badly constrained system.

During Order 2000 in SMD there was a concern not to implement LMP until there's a robust enough transmission network. LMP shows just how bad a transmission system is. If there's a somewhat robust transmission system then frankly either model might work.

Who pays is the question. It's going to have to be wrestled out in each region. Nobody's going to agree to pure roll-in and nobody will agree to participant funding outside of those people that it benefits. There has to be a middle ground.

Speaker 1: It's similar to the way in which wholesale retail cost allocation was done. The FERC used a 12 points to peak model for years. It was a formula based on peak demand, load use, etc. This could be done. A once for all time decision is a problem. Cost allocation will have to change because of changing load flows. Commissions still do transmission rate setting. They can figure out a way to use usage but change it over time to allocate costs. It's harder because the load shifts but the issue is the same.

Speaker 2: Let me also add, joint ownership. [laughter] SeTrans had pure participant funding and anything that wasn't a near term NERC criteria had to be paid for. Utilities wanted to know why they couldn't own the facility if they had to pay for it.

Question: When transmission and generation planning were de-integrated, it meant any generator could site anywhere as long as they have a connection to the grid. Having firm transmission to get to markets was not a requirement. Generation and transmission siting de-integration caused many of the problems that we have.

While transmission and generation can be substituted for each other, demand side will replace both. The power system is a large and complicated machine, it is not a transmission and generation system and a group of loads. Generators should not locate anywhere they want. There's been a drought in the planning of generation capacity and no consideration of a national perspective of fuel diversity. 92% of everything added to the grid has been natural gas. How can we optimize fuel mix and asset location to avoid things like the 2003 blackout?

Speaker 1: The purpose of traditional integrated resource planning is to do exactly what you described. I don't know how you do it in a

market environment. without impairing the markets.

Speaker 3: In Wisconsin the utilities and state commission considered fuel diversity a few years ago and concluded they didn't like bias towards gas. Now they are actively approving coal plants. There are two coal plants under construction that will be running within a year or two.

Fuel diversity is important. ATC in Wisconsin was set up because the nuclear plants got shut down for an extended period of time and people realized there was no transmission system to accommodate that. Since then there have been droughts in Manitoba that changed transmission flow of Canadian hydro, deliverability issues with coal, and high prices of gas. A robust transmission grid you can handle those. In these situations transmission is more than a substitute for generation. It enables the system to accommodate these kind of shocks.

Speaker 2: Another problem, especially in RTO regions, is the lack of long term transmission rights. When financing these kinds of facilities lenders and rating agencies want to know plant cost and whether there is an all in price that customers can afford for 30 years. In RTO regions the only thing available is a one year FTR and participation in the next auction. In recent PJM auctions some public power developers only got 50% coverage of their existing needs. That's not an environment in which new long-term base-load generation can be financed. There needs to be certainty in order to build, participate, or buy from merchants a long term commitment. That includes wind, by the way.

Moderator: In its next long term assessment NERC is going to consider more than normal events. This will include fuel disruptions, droughts, coal delivery problems. These have not been considered in the past. This is an evolution for the industry at the national level.

Speaker 4: Out west the model, particularly in Arizona, southern Nevada and New Mexico, is

jointly owned lines. Almost all high voltage lines are jointly owned among a number of utilities. It works very well. It is more cost effective for four utilities to build a 50 mile 500 KV line than for one to build it and hope others take service across it. Some merchants are beginning to take an interest in acting as owners in these jointly owned projects. It makes sense. Merchants will step up to support transmission investment and have to be able to justify it.

The Arizona Corporation Commission requires a deliverability study as part of their power plant siting process. State commissions have some authority in evaluating these processes.

Question: I'm concerned by the Entergy example because the inference is that if one builds an IPP, somebody else is responsible for getting the transmission built to get it to load. Certainly FERC is responsible for ensuring long term needs, reliability, and economics of load serving entities. Given that the law says that utilities have to ensure long term needs and economics, how should it be carried out?

Speaker 2: Section 217B4 does give the FERC added authority under 205 and 206 to require planning and expansion of the transmission network to ensure LSEs meet their long-term service obligations. That applies in both RTO and non-RTO regions. In RTO regions this is the genesis for the long term rights rule making. In non-RTO regions FERC is can pursue enforcement through the NOPR docket in part. They're also providing extensive transmission incentives but I won't address those now. FERC is aggressively pursuing these options and attempting to improve definitions, increase collaboration, and get results. However, you can have the right tariff provisions but unless people get their mind right and decide they really will sit down and plan with each other, then it won't happen. The North Carolina collaborative is a real step forward because of the change in thinking among stakeholders. It's the same thing with Cap X. Why can't that be done in Entergy, in Southern, or in regions with FERC litigation?

Question: I'd like to discuss the \$200 million tradeoff discussed in the Entergy example. The question was whether to continue to re-dispatch the system using RMR facilities that are more expensive or pursue a different course. In this situation we have a specific number. However, the middle of the panel said we shouldn't figure out what the number is, or use LMP to show the marginal cost to re-dispatch. As a dental analogy, we should never get a dental check-up unless we're sure we have no cavities or gum disease. [laughter]

If we know the information we need from the dental check-up, the problem and the cost to fix it, that is useful information. Whatever happened to economics and least cost for consumers? ATC is doing an economic analysis to determine the marginal cost of dispatch and when it's cost effective to build transmission. However, the emphasis in some of the other presentations is that planning is not about who pays, but what are we planning for? Is it so robust we never have to re-dispatch or have market power, or is it the least cost way of serving loads at the level of reliability we expect from them?

Speaker 1: My answer to the first question is yes, the entire purpose is the least cost system consistent with adequate reliability. This is a discussion about means rather than ends. If there's a problem, be it transmission congestion or inadequate generation, a state commission has to alleviate that problem over time. Most of these issues are complicated situations that you can't fix initially.

Speaker 3: The state law that allowed ATC to set up mandated least cost planning for the consumer. Whether it's distribution or transmission solutions is secondary. For instance, a local distribution utility may want a transmission solution but the transmission solution has to be lower cost than the distribution solution. It's a false dichotomy to delineate a difference between reliability and economics. ATC's approach is to determine the market impact, including congestion costs changes, when a facility is built. MISO just identified their 25 most congested flow gates

and five are in the ATC territory. Four of those are being addressed by projects already because they have reliability impact even without an economic analysis. The fifth one is being justified based on market dynamics using LMP. They tell the commission that the line will reduce overall cost to consumers. They know the costs and can make the decision appropriately.

Speaker 2: We don't need a full LMP calculation to know what needs to be built. One public power member in Entergy is constantly told their transactions will be cut. They must run their own higher cost generation because there's no transmission for them then. They know how much more it costs and the tradeoff. An RTO system with a single clearing price market will not solve this issue. An RTO approach is not a political reality for a variety of reasons.

Instead, there's a middle way that will improve that situation. Entergy representatives explain that the reason they keep the current transmission policies is to protect low income customers. I couldn't disagree with that more. A better dispatch would save low income consumers of Entergy much more than requiring participant funding of all transmission construction.

Question: One speaker observed that engineers should use consistent assumptions throughout all planning and operations models. However, the contract path method is used for some calculations but you don't want to use the contract path method in operations, do you?

Speaker: No. [laughter] There are no planners that use contract path when doing their plans.

Question: Then why do they post ATC, CBM, and AFC based on contract path?

Speaker: Because FERC told them to. [laughter] This issue is addressed in ComEd's NOPR comments in 888. Many stakeholders have said you can't do it.

Speaker 2: Those issues will be dealt with in the NERC process. This is an area that FERC really needs to address.

Session 2.

Regulation and Hedging For Load Serving Entities: Which Risk Is Greater, Regulatory or Speculative?

Depending on the retail market design, Load Serving Entities (LSE) face some of the full or the residual supply option for end users. Buying both energy and capacity in the market provides forward hedges. Volatility of prices, coupled with the availability of ever more sophisticated hedging devices, both physical and financial, make hedging seem perfectly reasonable.

However, a desire to avoid consumers involuntarily subsidizing or underwriting utility market speculation and avoid regulators – rather than professional managers – making market judgments, leads many to conclude that the risks associated with hedging may exceed the apparent benefits. Many LSEs seek prior regulatory approval of their hedging because they fear prudence disallowances in the event that market fluctuations may cause otherwise intelligent hedging appear to have been terribly wrong. That risk is aggravated by the fact that the costs of hedging are generally merely pass-through items that offer no upside benefit for risks assumed, and by the fact that regulators seem more likely to review active hedging than they are to look at the prudence of not hedging at all.

Thus, absent pre-approval and despite the fact that hedging can be done without it, many LSEs would be reluctant to enter into long-term contracts. On the other hand, risk-taking could be part of the LSEs' overall responsibility and management – not regulators – should be making decisions. Socializing the costs of hedging through the mechanism of pre-approval would remove a necessary element for assuring the sound exercise of professional and knowledgeable judgment. In markets where end users have a choice in suppliers, many proponents of competition see LSEs as only offering a residual service that should merely reflect the marginal prices in the market, whereas hedging products, of whatever form, should offered in the competitive market as part of customer choice. How much forward hedging is needed? How should regulators distinguish between LSEs hedging to protect their customers and LSEs speculating in the market? How should hedging be designed for energy, capacity or both? Who should make the decisions? What are the risks and rewards for performance in the hedging market?

Speaker 1.

I'll address the questions raised in the outline, give some quick answers, and then present some cases that demonstrate those answers.

Do the risks associated with hedging exceed the apparent benefits? If you're a shareholder of the risk, they definitely do. There are no up sides with one small exception. For customers, if volatility is a risk then there is a benefit because volatility is removed when hedged. It doesn't guarantee the lowest price.

Do companies seek prior approval of hedging plans to avoid prudence disallowance? Every

time they possibly can. That's axiomatic. Is there any up side benefit for risks assumed by hedging? Again, only to avoid a disallowance for not hedging. Are regulators more likely to scrutinize hedging transactions than to question the prudence of not hedging at all? They are just as likely to look at not hedging. As I will say later, not hedging is a hedge itself. Not hedging implies that a company can do better than the existing market by using the spot prices. Companies think that spot prices will be lower than if they hedge.

Does pre-approval remove a necessary element of management responsibility? Not if you're a shareholder. They want that certainty if they can

get it. Who should make the decision whether to hedge or not to hedge? The regulator has to say yes, you can hedge, not necessarily supporting or pre-approving a specific program but the idea that you do hedge. The purpose of hedging is to control volatility. We can look at the experience of the gas LDCs for insight.

How does one distinguish between hedging to protect customers and speculation? Hedging is described by regulators as an insurance policy. One definition of speculation is if one takes a hedging position without a corresponding market to serve. One is buying more than they need. Another characterization is if one is trying to beat the market. That's different than taking level positions going forward.

There are many examples of companies doing this sort of this. For instance, the unregulated side of Aquila asserted they were experts at controlling risk. About seven months later in 2002 they were in a disastrous situation and they ultimately lost about \$700 million in their hedging activity. Louisville Gas and Electric was taking hedging positions in 1998 and they lost over 500 million from bad hedging contracts. Recently, the Wall Street Journal focused on a 32 year old hedge fund trader who lost \$5 billion in natural gas futures in one week for Amaranth. My son was over for dinner last night, he turns 32 next week, I said what have you been doing? [laughter]

Regulatory decisions vary a great deal. Some jurisdictions have disallowed recovery of gas cost for failure to hedge. Others have said that companies have to do it. At least one commission has disallowed imprudent hedges for speculation. Many commissions have specific regulatory statutory hedging requirements. States that provide for retail competition have definite statutory or regulatory requirements. Alternately, a few commissions give no guidance. Examples abound of situations in which companies have specifically asked for guidance and gotten pre-emptive approval, or they've hedged and received a disallowance because they are told they shouldn't have, or they haven't hedged and

received a disallowance because they should have. Some commissions specifically refuse to give guidance, saying the issue is one of management discretion. Some companies get caught in a damned if you do and damned if you don't situation. New York had a generic proceeding in the late 90s and required gas companies to hedge at least a portion of their portfolio. 50% is the recognized norm for their hedging.

On the electricity side, New York has promoted competition, even recognizing that hedging could be a detriment to competition that allows a utility an unfair advantage. Nonetheless, they recognized that until the market matures, residential customers need protection and hedging. They suggested somewhere between zero and 100%. That's great guidance. [laughter] Nevertheless 50% is the norm there. The Commission has said that long term contracts will not be covered. This is an issue in New York, it's difficult to do a long term hedge. Fixed price options in New York have been allowed but new rulings are at a low return, with more risk than previously.

Massachusetts residential customers get a fixed rate from the company in which 50% of the load each year is set bi-annually. This is a de facto hedge. Commercial and industrial customers can opt in to the fixed price or take the current market prices. New Jersey's new auction process where the solicitation is one third of the market each year over a three year period. It's a de facto hedge done by auction and the utility has no control over it. Illinois has a contentious auction process that is similar to New Jersey. It's done by the commission with no choice by the company. Other states have a variety of similar plans.

The non retail choice states have various risk management plans mandated by commissions. Florida allows submitted non speculative, prudently incurred gains and losses to be passed through. The utility may also recover prudently incurred incremental offering and maintenance expenses associated with the hedges. Iowa's board allowed a hedge that is not speculative. In

Oklahoma companies have to submit a plan to hedge that is reviewed every two or three years. This is a problem if there is a mistake in year one, then the exposure goes along for 2 more years. The review should be yearly.

Washington's integrated resource plan doesn't allow for pre-approval but post action review. Wisconsin allows hedging costs to be passed on. In Georgia, Savannah Electric was told to hedge and it was allowed to keep 25% of the net positive financial gain from the hedging. There are two problems with this. First, it's not 25% of the gain or loss, it's only 25% of the net positive gain. Second, this creates an incentive for speculation, rather than hedging for non-volatility. They were part of a recent merger so the program is being reviewed.

Here are some conclusions. Hedging in fuel and purchase power is a useful risk mitigation tool. Generally regulators require it. Many states don't pre-approve, however I could only find two examples with a disallowance of hedging cost. The risk of being found imprudent for hedging if you have a legitimate, conservative hedging scheme is probably fairly low. Even lower than if a company doesn't hedge at all.

In states with retail choice the utility is regulated and there are few hedging opportunities available. New York is the exception but even there a long term contract has great risk.

Speaker 2.

I will address a few broad philosophical issues about hedging and procurement forward and then discuss the California process in particular. I'll also address resource procurement incentives.

It's important to distinguish between retail and non retail competition states. In a non competitive state, customers have no choices and there's extensive public interest in regulation. Oversight of procurement in retail competition states indicates a lack of commitment to the process. Nonetheless, there's

a number of approaches in retail competition states. Many confine procurement to a spot market or short term transactions with no meaningful hedging. Some outsource the default service obligation.

Risk is a tricky subject. Economists look at it in a stylized way, but other social scientists who look at other dimensions of risk that affect consumers in their own private life. There's status quo bias, regret theories, prospect theories, and others. It's more than a matter of looking at expected values and variances that economists tend to focus on.

Regulated procurement implies a principle agent relationship that is an inherently political process. A regulator is acting on behalf of consumers. They may have their best interests but there is also legitimacy in consulting them. I will emphasize that aspect in the California process.

Hedging is similar to the insurance markets. What do people think about insurance companies? Sure, they sometimes renege on their obligations after the fact. More importantly, when someone buys fire insurance and their house doesn't burn down they second guess themselves. After the fact reviews will always emphasize the decisions that go badly.

In California everyone emphasizes the retail rate freeze and the wholesale market that went ballistic. That is not the only story. San Diego Gas and Electric suffered from buying entirely in the spot market. Even though they could pass those costs on, it was impossible to do so politically and there was legislation immediately. The Department of Water Resources took on the procurement role when the utilities went into insolvency. By late 2002 the utilities were still not credit worthy. A statutory framework, Assembly bill 57, was enacted to reassure the financial community that they could support PG&E and Edison for procurement because the commission would de-emphasize or eliminate after-the-fact reasonableness reviews. The emphasis would be on preemptive standards for procurement. The

utilities are using the pre-approval process extensively.

There are vaguely constituted procurement review groups in the utilities; no “official” members but no one can be a market participant. There are no independent power producers. It is largely regulatory staff, environmentalists and consumer advocates. It is not a decision making body and they are not creating collective decisions. The utility presents their procurement plans and gives an opportunity to object. It is a constructive dialogue on a regular basis consisting largely of conference calls about every two weeks. It’s an active process. There are quarterly face to face meetings as well. This has created a level of mutual understanding about the challenges of hedging and reduces concerns because of the extensive information sharing. It functions as a conflict resolution forum somewhat as well.

The procurement plans have multiple dimensions in which needs are defined over a time period. The plans include procurement limits, processes and products, risk metrics; all sorts of stuff. It’s a sophisticated set of information.

Following the implosion of the merchant generation model, nobody’s going to build new generation based upon short term contracts. However, there’s no LSEs in retail competition states that seem to be ready to offer long term contracts because they don’t have a secure customer base. When and how can new generation be sited without long term contracts?

I used to think the basic generation service was a great idea because it addresses the issue of risk mitigation from the procurer’s side. The LSE simply farms out the risk of procuring power. People accept the risk voluntarily and get a risk premium for doing so. I’m not sure it creates the incentive for new generation. As a general rule, new generation is not getting built based upon these one to three year contracts. Something more is needed.

In California there are now year ahead resource adequacy rules that function really only as an early warning system. They’re trying to move towards longer term resource adequacy institutions. Utilities have been empowered to enter into ten year contracts with third parties and spread the costs of those contracts across all load serving entities within their service territory. This is only a transitional arrangement though.

I’ve talked to some power traders who used to work for Enron about the difference between hedging and speculation. There’s quite a few differences. First, the objective is to minimize cost, not necessarily make profits. The entity is working for regulators and ratepayers, not shareholders. Finally, when one is trading power there’s no load that has to be served. No transactions have to occur. LSEs have to deliver power and you’re going to have to get that power at a price. With hedging, the issue is do LSEs want to rely on short term markets or do they want to hedge some stuff long term? That means risk management as an employee skill, not some kind of speculative acumen. Typically the time horizons are a bit different too.

Power procurement is complex in terms of its dimensions. They’re not just buying for delivery next year, they’ve got the whole time horizon, including the day to day fluctuations. Procurement incentives is one way to do this but they are problematic from an economic perspective. Further, it’s hard to design them so they safeguard ratepayer and shareholder interests simultaneously.

Determining a benchmark to measure procurement performance is very difficult. Certainly LSEs want to avoid reasonableness reviews after the fact. Benchmarks can be either simple or complex. Further, they can be easy or difficult to hedge. For instance, all power can be bought in the day ahead market to reduce all risk. However, regulators want longer term hedges. Alternately, one could have a benchmark derived from a weighted average of short and long term prices. Again however, this is relatively easy to hedge but it doesn’t get you

much better results. One can do better by using a little more judgment.

Alternately, one can have broader benchmarks such as the average wholesale price throughout a region, or an arbitrarily picked price. However, these are random, and can make little sense. Utilities want to see a benchmark that makes some sense because they're going to get stuck with the variations that they may not be able to hedge. Thus the benchmark issue is very difficult to do fairly.

Speaker 3.

Here's a perfect hedge example. Two beggars in Rome set up shop in front of the church. One has a cross in front of him, the other has a Star of David. As people walked by, the guy with the cross kept getting all the money and the guy with the Star of David is getting ignored. There's a priest watching this and he says to the guy with the Star of David, "What's wrong with you, this is Italy, a Catholic country, of course they're going to give money to the guy with the cross. In fact, you sitting here with a Star of David makes it almost certain they will give money to the guy with the cross. The guy with the Star of David turned to the other beggar and says, "Who's the schmuck telling the Goldberg brothers how to raise money?" [laughter] Now that's a hedge. To my knowledge the Goldbergs didn't lose \$5 billion in a week.

Hedging has to be discussed differently in the context of a regulated market versus a retail competition market. In a regulated market there will be a regulatory policy or management discretion about whether to hedge. There's public policy and economic implications; the LSE is acting in a fiduciary capacity for the ratepayer. The retail competition market is different because the question is how the POLR [provider of last resort] product is designed, it's a policy question. How to stimulate competition, how much is served by the POLR market, and the potential that the consumer can choose to hedge themselves.

There are two ways to conduct hedging reviews, either *ex ante* and *ex post*. What does *ex ante* review mean? There are problems. One is information asymmetry. Utilities may miscalculate in hedging, so regulators can miscalculate as they assess hedges or develop hedging criteria. They're supposed to be protecting the consumer, they have no more knowledge about how to do that than utilities, probably less.

Utilities would like to avoid the risks. The problem is, is that appropriate? Is that really protecting the consumer? If there is *ex ante* review, this removes risk that may have created an incentive to perform more efficiently and/or carefully. Frankly, the skills in commissions are not up to the analytical task.

Another approach is that commissions could set *ex ante* standards and conduct an *ex post* review of what happened. There is question of how meaningful the standards actually become. There should be some kinds of standards for the prudence tests. Alternately, regulators should not be too prescriptive. Investor want them to be relatively prescriptive because it insulates them from risk. If you're a consumer that's not necessarily the best thing to happen.

There's a problem also of evaluating action and inaction. This debate is similar to the debate about emissions trading under the Clean Air Act of 1990. There were a lot of utilities who argued that emissions trading was the way to go for acid rain control. However, they realized they would be subject to prudence review and they decided they wanted command and control regulation because even though it's costlier for the consumer it's less risky for the utilities.

Historically, if utilities did something they were more likely to encounter regulatory difficulties than if they didn't do something. The sins of omission are less risky than the sins of commission. This occurs because actions are more noticeable than non-actions, except when prices really get out of whack. Second, intervenor groups are more likely to raise questions if the utility is actively hedging. It's

somewhat riskier for utilities to hedge than not. However, not hedging truly is a hedging strategy.

Another problem is that economic and regulatory risks are not the same. In theory regulators are supposed to replicate what would happen if there were a real market. In the context of hedging activity by utilities this doesn't happen. The economic risks are market uncertainties. They are also reflected in regulatory risks but there is additional regulatory risk via administrative and/or political uncertainty. In economic terms, hedging and not hedging ought to be equally risky. However, in regulatory review utilities are at somewhat greater risk if they do hedge than if they don't.

The big risk for shareholders is the non recovery of money spent in hedging or even non hedging. For the consumer the risk is not non-recovery, it's price volatility or high prices. Shareholders and consumers view this very differently. Regulators are under pressure to provide utilities with a safe environment for a prudent hedging strategy but also to protect consumers against high prices.

For regulators, when should they step in and socialize the risk? What is the balance between assuring investors and protecting consumers? How do you get these symmetries exactly right? Some argue that this is a good reason for retail choice, then the consumer can make their own decision and there's no concern for a prudence review although there's other issues I'll address presently.

There is also the question of distinguishing position protection and speculation. Key issues include the size and scale of the positions, the nature of the positions, and whether a company is merely covering what they have to sell or something more. Every utility needs an articulated strategy and statement of objectives for their hedging strategy. This should be done up front. In an *ex post* review this should provide some protection. If a utility has hedging losses and no strategy then they are in a bad

position. The documentation needs to be done on a regular basis, and updated as needed.

Pre-approval is problematic because management really should make a clearly documented strategy. This is actually a much better defense against prudence disallowances.

There are many forms of hedging, whether it's a forward position, buying and selling FTRs, a capacity arrangement, self generation, utilities being told by regulators to build reserve capacity, or contracts and expenditures on demand response. A utility should construct a hedging strategy that is reflective of all possibilities in the marketplace.

What about competitive symmetry? An investor might assume that in a regulated state they're at greater risk because it's less prescriptive and the regulators provide guidance. On the other hand there is greater management responsibility in a regulated state. In retail access POLR responsibility is a public policy and an economic decision as to the nature of the product who's providing it.

In a retail context, if regulators allow the utility to hedge this could discourage competition because potential competitors cannot offer much more. They can offer more or less risk in price volatility but it's less attractive if the utility is doing it too. They may offer their own hedging via green contracts, in buying this specific product they are insulated from the risks in the natural gas market for example. Demand side responses, such as load aggregators who might shut off things at peak times are possible too. Those forms of hedges should not be provided by the utility but by the competitive market.

There's a question of the distributor function. A regulator should define or limit what utilities or the POLR can do to hedge. They may order the utility to build to protect its position and insulate its consumers from risk. However, horizontal and vertical market power issues may cut the other way. In a competition context, states become far more prescriptive in defining the POLR responsibility.

Speaker 4.

I have a slightly different perspective on some of these issues. I haven't heard the word accountability. The party in the decision making role should have the accountability. My reason for caution with pre-approval comes from this. Alternately, all accountability with no reward leads to poor decision making.

To begin, there's three different kinds of companies. Distribution only with no generation, vertically integrated companies with generation, transmission and distribution, and finally distribution companies with generation owned by a parent or a subsidiary. Those are the toughest for incentives on the generation side.

With distribution only companies, the question is how to create the right incentives. PUC staff are unable to judge whether a risk management portfolio is reasonable or unreasonable. The PUC can judge whether a strategy balances risk and reward. It's good to encourage responsible hedging and risk management. Allowing the recovery of reasonable risk management is generally a good thing while still discouraging speculation, however it is defined. If a company wants to do it on their dime, that's fine as long as it doesn't cost customers. Even then, a spectacular loss could wreck the capital structure for the company and mess up its ratings.

Managing risk and price volatility doesn't make risk go away. There's a tendency to present hedging to public utility commissions as some kind of magic in which the risks go away. Risk management costs money. Hedging only reflects what's going on in the wholesale or retail markets, it's not going to fix problems in them.

The idea behind a prudence review is to have a rebuttable presumption, an action is presumed prudent unless shown otherwise. Monday morning quarterbacking is not necessarily fair. This approach for states with traditional regulation is very similar to past regulation with vertically integrated utilities. Economists argue for incentives or performance based approaches.

Regulators could create a profit and loss sharing mechanism. These can get more and more complex with time. Increasing complexity can't be avoided so specifically targeted incentives are needed. These are similar to past mechanism for improving heat rates at power plants or increasing the availability of nuclear power plants. These will be more effective than a broad based incentive such as price caps. Targeted incentives are what should be used to incent hedging. These work if the utility is allowed to recover some of the profits. The problem is there are almost always some unintended consequences somewhere else.

These approaches can be similar to allowance trading programs. However, allowance trading programs have a benchmark. The benchmark was the price of the allowances. Developing a benchmark with hedging is very difficult as we've heard. Developing some kind of profit sharing arrangement is probably the way to go.

Now, the hedging more broadly is risk management in a portfolio context. However, risk management has to address bilateral arrangements and power procurement. It may also need to include considerations for generation capacity and hedging for fuel. There are a wide variety of different considerations.

Risk management fits with traditional or incentive approaches, either is fine. However the model of distribution company with generation owned by a parent company presents a problem. The distribution company is purchasing power on behalf of customers, but the parent company's interests are to sell their power. Further, the jurisdictional split between FERC and the states doesn't help. Companies sometimes switch jurisdictions to get a better deal. There is not yet a good approach for this model.

Question: Typically there is a lack of symmetry with this issue. Distribution utilities experience more down side than up side. Are there any states that have achieved a balance between risk and reward?

Speaker 4: That is the ideal case. Usually, it tends to flip back and forth about who's benefiting, who's not. I don't have an ideal example.

Speaker 1: No. There's so much money involved that there isn't a program that looks at the end result in a risk reward context. A program that does that is essentially telling a utility that it's got to beat the market and doing that is speculating.

Response: What they're doing in California is worth considering. The regulator asks, "What is your program, how do you define it, what are you trying to accomplish, do you have it spelled out, is it in writing?" And then, "Did you go forward and execute it properly?" There really is no up side but you need a process that minimizes the down side as much as possible. If you do it that way then you're not going to have a disallowance.

Question: Are there any examples where they've actually built in an up side?

Speaker 3: Sure, Savannah Electric where they get 25% of the up side and no down side. However, that is bad regulatory policy.

There's two kinds of symmetry to keep in mind. One is the up side or down side for the utility. The other concern is an imbalance where one is more likely to lose by hedging than by not hedging. That needs to be symmetrical. It's not good if there is a regulatory bias to either hedge or not to hedge.

Comment: The reason there are only four cases of imprudence in not hedging on the gas side is that almost every gas utility does hedge. They started doing it in the late 90s and 2000 when the few disallowances showed up; they all started hedging. There are few exceptions. Those who don't have a commission directive not to do so, like Massachusetts or Connecticut.

Speaker: One observation that none of us mentioned. It's not just a matter of no up side for the utility because it's a pass through.

There's debt equivalence issues for utilities to worry about, especially with longer hedges. The financial community does not look at this as a wash, so this adds to the down sides and needs to be addressed at some point.

Question: It's worth noting that regulators looking back at a hedge that turned out bad will generally make careful consideration of the environment in which the decision was made. Generally, they are not going to penalize a company unfairly. However, a real risk is that the sample of regulators changes constantly and this is a risk to companies. They don't know when they are going to get a regulator who won't be fair.

Question: In California the approach to acquisitions sounds like a portfolio approach. This seems to make a lot of sense, particularly for residential customers who are not going anywhere. What about layering with long term contracts for residential customers as a way of further hedging a portfolio?

Speaker 2: The situation in California is a hybrid structure. The utility is buying power for 85% of customers that don't have direct access. Direct access customers can come back to them and tap into default service too. Returning customers have to stay for at least three years but the utilities are afraid of when retail access gets reinstated.

California differentiates between core or non-core. I believe the best differentiation is between core as small or residential customers who are bound to the utility, and large customers that can go fend for themselves. The final determination of this hasn't been done. In the meantime utilities are hedging forward quite a ways. Currently they are out five years. The holy grail will be ten year contracts, which are necessary to support new generation. Those are still not getting signed except under ad hoc regulatory mandates.

Question: The first presentation defined hedging as trying to achieve price stability to protect customers from sharp run-ups in price. How do

price variability and price decrease fit into this picture?

Speaker 1: Hedging doesn't protect customers or afford them the price decrease if gas prices go down. It's really an insurance policy against volatility. It's not designed to provide the lowest possible price, but rather a reasonable stable price over a period of time.

Question: This issue of price stability is important. Even if a price is a little bit higher, customers value the idea that they know what they're going to pay for electricity and for gas.

Why not use rate design at the retail level to help address hedging issues? Give customers the option to take some risk on their own or take a fixed price option; a menu of options.

Speaker: You envision a choice with some speculation in there that the customer could choose?

Question: Precisely. Let the customer make the choice and then let the utility implement that.

Speaker: Customers are worse at judging that than commissions. I'd be a little worried about that. Obviously this would only work for a retail access state.

Speaker 3: If you want to do that, simply open the market to give the customer that choice. Then the customer is going to take the POLR product or choose among an array of products, including hedged products.

Some utilities are offering a fixed price option, like NSTAR in Massachusetts. In that case the customer absorbs all of the costs associated with the fixed price option, it doesn't spill over to the remaining customers who are on a variable rate.

Question: I'm all for risk reward based on symmetry and the possibility of positive and equal negative gains if it's something that management has control over. If a utility is in a situation where they're buying fuel or power through an auction, they are a price taker. There

are indexes at which one buys gas on the spot market. If one is hedging and not speculating, all they're doing is buying gas on the forward market. There's a market for forwards and that's what they pay for the hedge. They're a price taker. There is no performance aspect in it.

Let's consider the Savannah situation. They have no risk as a utility by not hedging. Savannah had the ability under state law to pass through all of its fuel cost, and there was no risk to the stockholder before being asked to hedge. The state commission asked them to hedge but that puts Savannah in a more risky position. So the commission gave Savannah an incentive to hedge that was sufficient to reward the investor and still provide savings opportunities for customers. Can you comment on the argument for symmetry when management is essentially a price taker for the hedges.

Speaker 3: I'm not sure I'm following why management wouldn't have control. There are any number of hedging strategies they could follow.

Question: Yes, but they are a price taker for any one of those strategies.

Speaker 2: I basically agree with you. I think that some of these large purchasers may be able to beat the index but not substantially, and that's not the primary issue.

Question: Isn't that speculating if they're trying to beat the index?

Speaker 2: Let's set up a simple example where they're told to do 50% hedges and 50% spot and that's the benchmark. They can beat that benchmark by beating the price embedded in the index price. That'll be an observable market index price, a NYMEX price. Maybe they can do a bilateral at a lower price. There's also the quantity aspect. If the benchmark is 50-50 they decide to go 75-25 or 25-75 and take some risk on that weighting, doing more or less hedging. Nonetheless, there's lots of problems with these approaches.

Speaker: Most companies hedge with as little risk as possible.

Comment: If there's no reward they won't hedge at all. If there's some benefit to hedging, then the reward needs a split.

Question: The New Jersey BGS auction is a good approach. Another characterization is that a company putting together a hedging strategy can have an auction that they are responsible for. This gets out of the prudence review issues; simply take these products and have the market respond to it. There's quantity risk and other risks associated with it but if it's done well it reflects the best of the market. This is fundamentally different and simpler than providing incentives to the utility.

It does not solve the problem of building generation. However, it does provide comfort for IPPs that regulators won't have to intervene later if prices go wild. That's one of the biggest risks they face. Almost all the problems go away in the case of the BGS auction.

Speaker 3: If it's a POLR product that may be true. In a non-restructured state with utilities with their own generation, it's a lot more complicated.

Question: I don't see why that is. Unless they're a net seller they're still going to be buying in, they are still the price taker.

Comment: This was proposed in a state that was at least 50% vertically integrated. Some stakeholders testified against it in the procurement proceedings. If the utility is controlling part of the generation and auctioning off a substantial residual on a slice load there is no way that those on the other side bidding for it can protect against *ex post* gaming the utility manipulating the generation once people are committed to the slice load. It's a bit complicated. They're buying into a slice of the load dependent upon how they dispatch part of the system that they control. There are moral hazard issues.

Question: This is similar to the market power problem that has to be addressed. Or is there something fundamentally different about it?

Speaker 3: This could also bring back the stranded asset question. Suppose the utility has this in rate base and you're going out for an auction. Unless it's solely an energy auction and not capacity, it does get complicated in sorting it out and one could end up with another stranded asset problem. In a restructured state it's an easier question.

Speaker 4: One can't divorce the hedging expected of a distribution company from the procurement process. There are a lot of ways to acquire contracts through a BGS auction like New Jersey's. The Delaware or Maryland approach to the auctions would also work. The prices were very similar in the last round of these auctions. They were two or three months apart but all similar in price. They were in basically the same region. So I'm not convinced that the methodology is doing much. It's only reflecting what's going on in the wholesale market.

Bidders in these auctions are going to get basically the same thing; this mix of one to three year contracts and they assume some of the risk. This is consistent whether it is a procurement, BGS style, solicitation, or a clock auction. This is a good result. It's not necessarily an endorsement of BGS but rather an endorsement of having a good portfolio mix, however you acquire it.

Question: Yes, the BGS auction is the end point of no discretion on the part of the utility. This is important because of the risk they're taking and its prudence later on. There's no judgments they have to make, other than getting NERA to run the auction.

Speaker 3: However, if the utility is acting in a fiduciary capacity then there needs to be some judgment exercised. They are acting on behalf of their customers. An authority mechanism in the absence of customer choice is problematic. The

consumer's not getting protected in that scenario.

Question: That isn't computing. We hear these concerns and ask how to solve this problem. If I were the utility, I'd set up the BGS auction because that's the best way to get the best price and other things in the marketplace. Make it transparent, go straight through and don't take the chance of independent judgment.

Comment: This is regulatory lumpiness. In a non-restructured state three years may not be enough. So how long term do you go? Should NERA be used for a 10 or 20 year auction? Right there, the utility has made a decision to do 3, 5, 10, 15, or 20 year terms in the auction. The utility is subject to some risk, there is some imprudence. If you do three years the risk is that it's not long enough. The utility is imprudent for not going a longer term. That's the lumpiness they face.

Question: That's a fair point. However, it's much simpler to get pre-approval on auction terms than on actual contracts themselves.

Comment: In the early 80s a small holding company called Unatil ran in New Hampshire. They used to take their power from PS&H pre-Seabrook. They saw the wisdom of getting out from PS&H, set up their own shop and did power procurement. They owned no bricks and mortar. Everything was done by purchase power and they set up short, medium, and long term contracts all the way to 20 years. They did it through fuel diversity, trash burners, gas, nuclear, whatever. They set up a very good portfolio and received regulatory blessing to do it.

Response: That may be more flexible than a yearly auction for one third of the load.

Comment: It is because there was always a mix of short term, a variety of power turning over, and some long term contracts.

Response: They could be unlucky too. They can make a mistake.

Comment: Yes, but it's prudent and/or pre-approved.

Response: The mistake isn't prudent.

Question: I assume the overarching goal is to avoid rate shock or volatility for residential customers. Another option is the credit card option. It's called budget billing in some states.

If a utility is attached to an ISO with a real time market, they buy power at the real time market price. If the regulatory goal is to avoid customer price shocks then they use the credit card approach and smooth those prices over a longer period. That addresses volatility. It doesn't solve a market power problem but that's not the issue here. Assuming the real time market price is legitimate then the hedging legitimacy questions are moot. Should that be on the table?

Speaker: It sounds like California in 2000. 100% reliance.

Question: Even if utilities could have hedged in California 2000 what would the price have been in the forward market? There were a lot of forward market prices that are being litigated now.

Speaker: The forward prices probably would have been better than what the DWR [California Dept. of Water Resources] got six months later in the forward market. Duke was offering forward hedges at \$55 a megawatt hour that went out five or ten years.

Question: What they were doing was smoothing. They saw the forward prices for gas five or ten years out and they were back end loading the price of power.

Speaker: You could argue they were taking the back end and making the front end prices more palatable.

Question: So the experience of California 2000 took that option off the table?

Speaker: California 2000 illustrated that having that much in the spot market invites the exercise of market power. Especially in a market that was already inclined to be that way anyway.

Question: So forward hedging strategy mitigates market power?

Speaker: Yes, to some extent. I didn't hear anybody discuss the benefits of hedging in market power.

Question: That isn't the topic of this session, but it's an interesting claim. I don't think it solves it.

Speaker: The other problem with an all spot market credit card proposal is that a large credit card would be needed, especially post Katrina. \$5 billion, or multiples of that, could be required. In the spot market, an LDC selling gas would have to dig deep to pay the price.

Question: What about Maryland's situation? They are coming off a ten year rate freeze and the prices will be going up. Is there value to financing that rate increase?

Speaker: You're proposing to put them all on the spot market and hope that the fluctuations there will settle at some level form. However, the spot market is both volatile and expensive on hot days. They could really run up a credit card bill. How many suppliers to large groups of retail customers use this approach? Very few, probably none.

Question: Use which approach?

Speaker: Put everything in the spot market and no long term perspective in the market.

Question: Yes, that's what retail suppliers do.

Speaker: Not 100%. They do some combination, right?

Question: No. They might do 100%. It depends on their portfolio mix is and customers needs.

Speaker: But that's my point, it's a portfolio mix, it's not one thing.

Question: I'm concerned about the virtue of removing the utility as the intermediary and having the regulatory agency produce its own decision making. We've heard how a 32 year old Carnegie Mellon quantitative MBA was able to wipe out the market cap of half the publicly traded utilities in the country. \$5 billion in four trading days. This is a hedge fund that ostensibly had the most advanced trading and risk management strategies. The idea of putting utilities in the role of hedging entity and having to litigate hedging and purchasing strategy is a bad policy.

Nonetheless, regulation has and will be a process where 20-20 hindsight will be exercised with great precision. That's a reality. Fuel price volatility is also an ongoing reality. There's only a minimal down side for utilities. They might get clipped a couple of basis points on their return because the PUC has taken over some of their managerial and entrepreneurial role. Other than that, most utilities would be happy to remove the issue and let the PUC manage the risk. It removes them from the position of having to choose a lose-lose strategy. At least for the current regulatory context.

Speaker: The utility's involved too, even if it's a pass through. There are certain things that they cannot pass through for political reasons. Further, utilities would not want to pass the responsibility for hedging to the commission. It makes sense for the utility to hire expert agent advice and advise the commission as to what it's doing. If the commission blows the whole process it will come back to roost with utility shareholders. There are ramifications for everybody.

Question: Those ramifications can't necessarily be any worse than if the utility was directly involved.

Speaker 3: If you follow that scenario then, what would you set the rate of return for a utility at?

Question: That is my point. I'm surprised this question hasn't come up in Jersey but I'm sure it will at some point. In effect a substantial portion of the risk is removed from the procurement function. What's left, and what kind of real return are they entitled to?

Speaker 3: Yes, but in New Jersey, Illinois, and states with retail choice, it's a different kind of question. Designing a POLR product where there's retail choice is less complex and one could use something like the BGS auction. That's fine because the customer is not bound by it. However, in a regulated environment where the utility is working on behalf of the customer it's a different set of questions.

Question: If a utility has reliance on market driven resource acquisition, one can design a process that determines whose discretion was exercised. Further, if regulators are going to use 20-20 hindsight then they should be the ones stuck with the decisions.

Speaker 3: I'm not sure the 20-20 hindsight assertion is quite right. For instance, in Nevada most people thought the disallowances were too meager. I believe it is a 20-20 hindsight, lose-lose situation for the utilities. That's a stereotypical mischaracterization of regulation.

Question: What should the measurement should be for utility management and what are the right incentives? Management can make large bets in the regulatory process. In California, the utilities were involved in the design and implementation of the market structure. There was a structural bet in that market in which everybody just knew that prices would go down under deregulation. Utilities got to keep retail customers, got rid of stranded assets, converted purchase power contracts to settle against the spot market price because you know that's going to go down. They were basically betting with somebody else's money. Did any utility executives lose their jobs over this?

Speaker 2: I wouldn't agree with your characterization necessarily. Your more timely question is this: does it make any sense to have

utility people placing bets in hedges without any risk? Utilities are concerned about their competitive situation and ability to recover costs. They are not the same as any free market trading company out there.

My imperfect answer is that the current California process doesn't work too badly. The procurement review groups ensure everybody understands how complicated things are. It puts a burden on the professional staff of the utility to educate people about what is reasonable and/or ideal, but overall it is functioning well.

Response: The utility should not be in a position of betting, that's speculating. The utility should insure price stability. That is a regulatory policy in most states. Customers don't like volatility and they vote against commissions or governors who allow prices to go sky high. It's a social policy. If a utility doesn't provide stability or adhere to an approved program, then they're imprudent. It's not a bet.

Question: New York is a retail choice state, and 70-85% of the C&I customers are now with ESCOs. However, residential customers are least likely to move. Movement away has been slow though steady but they are not fond of volatility.

Utilities have a wide variety of different behaviors. Some are in the day ahead electricity markets for their residential customer supply and others have long term contracts that run out eight years. Somewhere in between is a reasoned approach or perhaps both are reasoned approaches. What is the role of the utility in hedging for residential customers who are least able to respond and least tolerant of volatility.

Speaker 3: There are two options embodied in the core versus non-core approach. The non-core is already defined, and those C&I customers are gone. Does a regulator want core customers to be treated like traditional utility customers or do they promote competition and have a plain vanilla POLR product derived from a BGS auction or flowing through the market via the NYISO price? Come up with something simple; it doesn't even have to be the utility that's the

POLR provider. The objective is to open up the market, or at least allow it to be open. If regulators want an agent for the consumers in the core then rely on utilities who have the expertise to protect the customers in a sophisticated market environment.

Non-core customers haven't left because it's not worth their time to figure out how to play the market, they don't have the skill to do so, or both. If that's the case then the policy decision is whether a regulator wants ESCOs to assume a greater market share because they're stimulating competition. Otherwise, let the utility play its traditional role as the supplier.

Question: In this context, how do we get new generation built? Some have suggested that ten year contracts are necessary, others say other market mechanisms might be enough for the market to build generation. In the late 90s and early 2000 everybody built merchant under the presumption that they would do OK. That is no longer the case.

How can we reconcile mechanisms like BGS which use short term contracting and this need to build. Can we make the portfolio approach and the BGS approach compatible?

A separate point involves this gaming question. Assume I sell a slice of the system in the marketplace and I bid seven, eight, ten cents. Then another player separately buys a whole lot of base load generation. Suddenly, the rate associated with the residual is a higher price for that residual load. There's clearly an interaction and a risk for me bidding in the auction if someone else can take away the base load that I assume I will supply at below the average price that I did. How do these pieces fit together?

Speaker: That's an excellent question. We need another panel for that. [laughter] It's a serious problem. Hedging or not hedging will not address that issue.

Question: Some commissions want customers to see the volatility before they take action. They want a short term market. Other commissions

have recognized a longer need. A conscious decision against hedging says they're not going to do long term contracts.

Comment: While some commissions have taken that position, some legislators have decided they will not tolerate volatility on the consumer side. What has resulted is a restructuring of the restructuring which includes long term contracts for generation, participation in the competitive market, and other kinds of IRP similar operations.

Speaker: There are some potential gaming issues when you start mixing these two things together. Nonetheless, some combination of short term BGS that satisfies near term issues combined with something like capacity markets with LSE obligations to purchase a minimum amount of capacity rights on a forward basis could work. and try to go to a highly liquid kind of capacity market but have some requirements to purchase forward there. It would be useful to lift some of the caps over time in the spot market as well.

Comment: Like Texas.

Speaker: That's the kind of thing that I have in mind. Getting there is going to be a real art. In states where utilities don't have a long term portfolio already, then a long term portfolio should not be required unless one secures their customer base somehow. That would be inconsistent.

Moderator: Five to four and we have three more participants which is to suggest that we'll need brief response. Dave and then there's Steve and Becky.

Question: Actually, utilities and consumer interests are completely aligned. If rates are volatile and increasing, then utilities are hurt in the rate making process. They make less money. It's in every utility's interest to have stable low rates. Thus, the utilities are the right ones to have these RFPs. These are hard to do and complicated. Second guessing in the regulatory process for accountability creates a problem. The incentives are in the right place. When there

is no return on the utility side, their decision making may not benefit the customers because all the risk is on their side. It's asymmetrical.

Speaker 3: Yes, it is asymmetrical. However, that's been true of fuel supply, and purchasing energy. There's nothing unique about hedging in that regard.

Question: Whether core or non-core, is there anything about offering a variety of choice to customers that is inconsistent with a regulated utility model? Why can't a variety of pricing options within the context of the regulated utility as the commodity supplier be allowed?

Speaker: Offering customers various options is a good idea. There are problems in terms of risk implications for the portfolio, and cross subsidies across customers. What's to keep sophisticated customers from jumping into the portfolio mix when it's a good deal and back into another offering when it's not? If you control that then it's better. It may not be so easy as it sounds.

Question: The customers would have to agree to it for a fixed period of time. Competitive suppliers do that, they have to sign up for a one year deal.

Speaker: It's easy in the gas industry because the pipelines coming in are consistent. There's supply, they get customers that want a one year deal, they buy gas for one year and there's a perfect match that is hedged perfectly to their load. This works in competitive states because the utility doesn't have any generation. In a regulated environment the utility has to build generation and they don't know how it's going to work over a period of time. Utilities in New York have offered fixed price options for

customers who wanted to commit for one or two years. They don't own generation. They, hedge to exactly the price that they offer. In a regulated environment it's a more difficult question.

Question: One speaker asserted that managing risk and price volatility doesn't make risk go away. What kind of risk is left? If they're hedging and they do a financial swap, trading an equal and opposite position in the futures market, that sets their opposite position, index or fixed, that addresses price volatility. What risk is left?

Speaker 4: In the long term, they can only hedge for so long. If prices are drifting up they'll have to pay higher prices somewhere farther out. This manages the risk for the time period but that's all. Over the long run they're still following the curve, the direction the market is going.

Session 3.

An Agenda For More Perfect Regulation In Less Perfect Markets

After California, after Enron, after SMD, after EPCRA II, after Order 888 tweaks, after supply surpluses, after low prices, after Maryland, what is a regulator to do? Good market design is a critical challenge if investment and operating decisions are to be driven by market forces. But good market design is not easy in the best of circumstances, and present conditions are not the best of circumstances. Different regions

on the same grid pursue conflicting approaches to electricity markets, from reform to resistance. Even the best intentions can go astray and market designs are incomplete. Hybrid markets are the norm, meaning that simple hands-off regulatory policy for markets is not likely or desirable. But regulatory interventions create their own dynamic with small interventions having large unintended consequences.

Resource adequacy requirements, portfolio standards and national transmission corridors are symptoms of the pressures and trends that rely more and more on regulatory decisions and less and less on markets. If regulation must replace markets, is the best approach to muddle through, or would a new regulatory strategy be a better approach? And if support of markets is to be the policy, how can regulators make modest corrections without undermining the market? Are the trees planted by regulatory policies obscuring the forest? Is the forest service lost in the woods? If electricity markets don't work, or are not enough, what is a regulator to do?

Speaker 1.

We are asked to discuss how to perfect the ills in markets, traditional regulation, and hybrids in between. I've broken down my comments into three sections.

First I'd like to address the retail electricity model. Those states' model has become divorced from the traditional model of insuring obligation to serve and reasonable price. This has severe political and economic ramifications. How can those states regain control of their destiny, their economic future, and structure a more sensible path going forward? Second, traditionally regulated states need to better integrate competitive wholesale market options, employ more regional evaluation and procurement strategies and adopt a broader service vision for an enhanced regulation framework. Finally, federal regulators have a strong role to play in both types of markets.

It seemed that there was an assumption, explicit or implicit, embedded in the topic description that electricity investment and operating decisions should be driven by market forces. This creates a characterization of those resistor states, presumptively the 33 states that did not adopt retail competition and have maintained the standard regulatory framework. However, the market based pricing philosophy for retail service is limited to 17 states, It is not a universally accepted goal.

Recent history shows the 33 regulated states have maintained rates at a low cost with reliable

service. They've avoided the 10-20 cent per kilowatt hour rates that reformed states have seen recently and they don't have to worry about whether new generation is going to be built.

I'll focus some comments on Arkansas. Their legislature was initially lobbied into passing a retail competition statute in 1999. In less than a year their commission realized that Arkansans would pay much higher prices under this scheme. Consequently, they engaged a consulting firm to perform two cost benefit evaluations that compared cost of service rate-based regulation versus generation service priced at market. This included three gas price scenarios. The highest scenario did not exceed \$5 per MBTU out to 2012. Even at that their prices would have risen by 15%. At today's prices, our highest cost utility's rate is 5.9 cents per kilowatt hour. Compare that to the 10.5 cents per kilowatt hour for Exelon. This would have been a 78% rate increase for Arkansas customers. That would have been an unconscionable rate increase. There but for the grace of god and fortuitive due diligence goes Arkansas. Given this scenario, how would a restructured state want the wholesale markets to be structured differently?

Electricity generation is not a homogenous substitutable commodity. It cannot be left exclusively to markets. We need to reconsider the economic rationality, political viability and consumer equity of using a single price market clearing concept in which low cost nuclear and coal assets are priced at the marginal cost of a

gas fired unit. This feature of wholesale markets is the primary reason for the rate increases in retail competition states and the resulting political pushback.

The words “reliable” and “reasonable cost” need to be returned to the regulatory framework. Wholesale pricing models that reflect prices closer to actual costs plus some reasonable profit margin. If we don’t do this we will cause irreparable harm to this nation’s economy. The 17 deregulated states represent about two thirds of the population.

I have a two tiered strategy. If we continue looking at electricity as a homogenous resource we miss the opportunity to price it accurately. FERC should open an investigation that examines a replacement of the single price concept with an alternate approach to the just and reasonable concept in wholesale markets. One idea would be to institute different market clearing prices for the different constituent elements of the curve: base load, intermediate, and peaking supplies. Alternately, establish different market clearing prices based on the fuel type: nuclear, coal, hydro, gas, oil, renewables. A combination of different fuel types and different elements of the load curve. Some economists assert this approach doesn’t violate economic principles. I’ve been told it would be easier to use the approach based on fuel types than load curve elements.

Electricity generation absolutely has to be provided with different types of technologies and fuels in order to be both reliable and reasonably priced. Reasonably priced means the price bears some resemblance to actual cost. Differentiating the price based on the different constituent elements of electricity service has several benefits. It would send signals as to when new generation of different types needs to be built, identify which generation fuel is most cost effective for a specific application, and eliminate inflated prices and excessive profits. These profits occur because the highest cost, highest bid fuel is used to price all generation regardless of the role that it plays in the load curve. That is what is causing problems in retail

competition states. Consumers would see the benefits of head to head competition and have a rational cost basis for the prices that they pay. It would lead to more price transparency and create a win-win effect for consumers and generators.

Restructured states need to work with legislators to reinstate the long term obligation to serve in state statutes. Any LSE could have the obligation or opportunity to bid on load to build a plant. They need to do load forecasting and IRP to provide the flexibility to serve their consumers as best fits that particular service territory. Hybrid portfolios of resources, blends of plant ownership and long term contracts would remain but we need more flexibility in those state statutes.

I also have suggestions for regulated states. They need to reexamine planning and resource procurement on a broader regional basis. Vertically integrated utilities there, many that are multi-jurisdictional and participating in RTOs, need to use a regional IRP approach for options analysis and resource portfolio optimization. Independent cost comparisons between self-billed generation and competitive procurement solicitations should be required. A diversified fuel mix, moving generation closer to load, and better analysis of all-in new generation and transmission investment costs are needed. This includes implementing demand response and energy efficiency measures in forecasting and IRP processes, and utilizing the consulting role of RTOs for this more effectively. Commissions should be more inclusive of all stakeholders to address the kinds of problems discussed in an early session with Entegra.

We can create a more unified approach if the restructured and regulated states converged on these issues. The wholesale market needs to be robust and competitive. A market defined by multiple and fuel diverse generation sources with prices differentiated by fuel type and role in the load curve can be successful in either a traditionally regulated or a retail competition state.

The transmission grid is a key element of both models. It needs to be networked with sufficient capacity to allow generation competition. The retail regulatory structure should have enough flexibility so state regulators have some control over the process used for generation selection, construction, procurement and pricing. This approach could get generation built where it needs to be in time to prevent scarcity pricing. Transmission could be built up enough to allow regional IRP processes to function in either model.

Speaker 2.

I'm not going to debate whether markets are a good thing or a bad thing. I'll focus on issues for restructured wholesale and retail markets in the Northeast, Midwest, California, and Texas. Regulating markets sounds like an oxymoron. However, all markets are subject to a variety of regulatory mechanisms. These include everything from antitrust laws, environmental laws, health and safety regulations, disclosure rules, contract tort and property laws, energy efficiency requirements, content requirements, labor laws and minimum wages. In textbooks they may be characterized as unregulated but practically they're subject to a complex regulatory framework.

What is unusual is for the government to regulate final goods prices and market entry. That type of regulation has been reserved traditionally for a small number of industries. That number has declined dramatically since the late 1970s as a result of deregulation. Electricity markets don't design themselves, they're designed by human beings and we should expect some imperfections.

Second, restructured electricity markets still carry a host of engineering reliability rules from the old regime. Many economists don't account for this appropriately. The NPCC one day in ten year rule that existed before 1998 still exists today. One of the real gaps for markets is harmonizing reliability rules in a reasonable

way. Current trends in this area are the wrong approach, an issue I'll address later.

The academic literature on regulating markets presents two views for government regulation. One is a public interest view. Government regulates to fix things that aren't working well. In the context of electricity markets it would to fix or mitigate the consequences of market imperfections.

But there are also private interest views that affect the introduction of regulation. For instance, protecting incumbents from competition. This creates a dynamic of income and wealth redistribution by cross subsidization. Trucking regulation had that attribute for 50 years. It comprises everything from protecting low income people to protecting large aluminum and steel companies from competition. Taxation by regulation also occurs. That's a use of the wires to pursue a variety of good social goals off the budget. Just put them in electric rates. This approach has a long history in the United States in practice and theory. Some private interest views are incompatible with competition. Interest group goals often aim to suppress or distort competitive forces.

I will focus on the public interest view and mitigation of market imperfections. One approach is to identify the nature and consequences of the market imperfections, and efficient mechanisms to mitigate them. This must be done so adaptation is possible to market changes that alter the costs and benefits of regulatory mechanisms. In principle, many market imperfections can be fixed. It is important to balance the costs of imperfect markets against the costs of imperfect government regulation. Both regulators and markets have imperfections.

Why would we want to have government intervene in wholesale electricity markets? Clearly, there are a variety of imperfections in the design, behavior, and performance of wholesale electricity markets in the US and in other countries. The imperfections have improved somewhat over time. The markets in

New England, New York, PJM, and Texas have different attributes that work well in a number of dimensions now. This took nearly ten years of fiddling with them. There are some remaining problems with the markets but they are understood and can be fixed in theory. They do face political and institutional barriers, so change may be slow.

Some market imperfections cannot be fixed easily, mostly in terms of reliability. Reliability is a collective good and its implementation by system operators is not readily recognized as prices and costs in markets. Further, efforts to fix one market imperfection can create another. \$1,000 price caps occur almost everywhere. Where did \$1,000 come from? Somebody made that number up. This cap mitigates market power under some contingencies but when capacity is fully utilized it keeps prices at too low a level. This creates significant distortions in investment incentives for peaking capacity and capacity overall. It also creates incompatibilities between engineering reliability rules and the functioning of markets.

As I address various regulatory interventions, the overriding question should be, “does it make things better?” This is better than the World Bank’s goal of “do no harm.” We ought to make things better, not simply avoid making things worse. The second goal is asking whether the interventions accommodate continuing improvement in market design.

The development of capacity obligations and markets in New England, New York, and PJM has been extremely constructive. In New England this was a difficult process but one in which all stakeholders were involved and learned from it. These markets do not produce enough money to stimulate investment consistent with the current regional reliability rules and needs. There isn’t enough scarcity pricing, there are market power concerns, especially in load pockets, and there are incompatibilities between reliability rules, emergency protocols, and market mechanisms. Many suppliers and some buyers think there are inadequate opportunities to hedge market price

volatility. There are concerns about the continuing redesign of markets and regulatory uncertainty once for current and future investments. There’s inadequate demand side participation, I’ve already mentioned the problem of price caps.

The capacity obligation market settlement approved by FERC in New England has many desirable attributes. It’s not perfect, but it represents an example of government intervention stimulated through a collective stakeholder process that will make the market perform better. It responds to specific imperfections, it’s compatible with reliability rules, and it accommodates further reform. For instance, if New England were to raise its price caps or implement a more effective scarcity pricing mechanism, there’s a scarcity pricing credit feature that accommodates those kinds of changes. It’s compatible with retail competition. The capacity obligation goes with the customer. There’s no concern that a particular retailer will go bankrupt. Calculating the capacity obligation is mediated through the ISO. Ultimately every LSE will have to pay for capacity by self supply or by buying out of the capacity market.

This will eliminate the need for costly and inefficient regulatory interventions. RMR contracts went from 1,000 megawatts to over 7,000 megawatts in New England – they will be reduced. Similarly, it works with price caps because it provides a hedge against high prices that exceed a certain level. It could be improved, in particular by improving the integration of load management programs and retail prices. This could be done fairly easily in the future.

Renewable energy portfolio standards (RPS) are next on the list. This is not the most effective way to internalize environmental externalities. It encourages cost reductions through learning by doing, and is a form of taxation by regulation. State governments like it because they hide its costs outside of the state budget. That being said, over twenty states have renewable energy portfolio standards.

There are some RPS design issues that encourage specified contributions of renewable energy to the electricity mix. They can be made compatible with wholesale markets. Market friendly RPS programs are fully integrated into the wholesale markets. The ISO plays a role in tagging the green electrons for suppliers and buyers, and monitor the system of tradable certificates. A backstop price is important or the market could collapse if supply doesn't emerge as people anticipate. Interstate trading is very important. Incompatible programs between states cannot function in regional power markets; the RPS programs must be linked.

Most states allow for out of state supplies and certificate trading. The Massachusetts program is superlative. It's fully integrated with the wholesale markets, the ISO plays a significant role, and there is a tradable permit system with low transaction costs.

The major problems are not always market oriented. Siting renewable generating facilities is challenging, especially windmills. In Massachusetts they're learning one shouldn't try to put windmills where they can be seen by the senator, the governor, and Walter Cronkite. [laughter] Financing without long term contracts is challenging, though the four capacity markets in New England will help that. There's always a question of how the state will effectively use funds generated from selling permits.

Demand side response. In 1998 many thought the invisible hand would stimulate the demand side features needed in robust competitive markets. I was skeptical then and now. The absence of an active demand side is a major imperfection. System operators want or need controllable demand; demand that can be called upon day ahead, hour ahead, or within ten minutes. They intervene before demand elasticity and real time pricing can mitigate prices. Developments here in New England, Texas, and New York are good.

One flaw that reduces demand side participation is that prices are too low. There is an asymmetry between the supply side and the demand side. A

footnote in one of the consultants' reports in the FERC capacity settlement states the implicit value of lost load from the NPCC one day in ten year rule is \$156,000 a megawatt hour. That's 156 times \$1,000 a megawatt hour. We don't pay more than \$1,000 on the demand side but on the supply side we pay the equivalent of \$156,000. These prices need to be more integrated.

Finally, let's discuss transmission planning. The market will not stimulate appropriate levels of investment in transmission. There are opportunities for merchant transmission investment but generally we need a robust planning and regulatory framework to realize that goal. The distinctions in some ISOs between "reliability" versus "economic" transmission investments are meaningless. Reliability and economics, by that I mean reducing congestion costs, are completely interrelated. When one adds transmission for reliability reasons in southeastern Connecticut it changes the LMP. When one adds transmission capacity connecting PJM to Long Island, it provides reliability benefits. They cannot be separated, the Europeans have recognized that. There are serious institutional imperfections here. A well designed regional and inter-regional transmission planning process will improve the performance of these markets.

Regulatory interventions focused on mitigating the effects of market imperfections can improve market performance. That should be our focus. They should be done for public interest reasons and not private interest reasons. Finally, they should meet efficiency and adaptation criteria to be successful.

Question: What would be adequate participation from the demand side?

Speaker 2: It depends on the kind of demand side participation and the reliability criteria. Generally, it's a relatively small amount. If one looks at the top 1% of the hours a year and took the difference between the peak load and the load at 10%. That would indicate an appropriate amount of demand side. It would have a

desirable effect, especially if price caps are eliminated or increased.

Question: That's about 10% of the peak capacity, generally.

Speaker 2: Exactly. If we examine load distribution, 10% of capacity is needed for fewer than 1% of the hours. There is a lot of capacity that's almost never used. A more effective demand side would reduce much of that capacity and the market would have the right prices that reflect the value consumers place on reliability.

Question: In Connecticut it's approaching 9% of the capacity there, especially during the last three years with the southwest Connecticut transmission problem.

Moderator: In the various RTOs, what is their demand response goal? New England has adopted a goal that eliminates a significant percentage of their peak via demand response.

Speaker 2: Other than California, there are not goals around demand response. There are initiatives in almost all the RTOs and vertically integrated utilities in places like Arkansas, but it's ad hoc at this stage.

Moderator: Although they are unpopular in New England, ranchers and farmers in the Midwest, Southwest, and far west love the annual lease payments that come with windmills.

Speaker 2: Quebec has a large set of wind farms under construction. This is a perfect place for wind because there's a large hydro system. They use the wind to store the water effectively. Land owners get \$1,000 a year per windmill and they're quite happy with it.

Speaker 3.

I'm going to focus on imperfect regulation, particularly at the federal level with FERC. Generally, market stakeholders don't ever believe that regulators make all the right decisions. They're never perfectly efficient.

Regulators have information costs; they never have optimum levels of staff, expertise, or information.

I'll focus on two areas: infrastructure development and market design. FERC's transmission incentives rule making has been somewhat controversial because some actors think they're giving away too much. There are other useful actions they can take that are simple and non controversial. For instance, recent provisions of up front guidance in a declaratory order about how a particular project will be treated. This provides certainty for investment financing. Regulation just won't set returns and determine cost of service years after facilities are constructed. Generally, this uncertainty needs to be allayed with other simple actions that regulators can take to help with investment. Alternately, they can just get out of the way. In certain circumstances, reducing regulatory burdens allows companies to move forward with investment and construction.

FERC is not optimally situated to determine if transmission should be built, how much and by whom. Instead, they should ensure sufficient information so shareholders and customers can make appropriate decisions.

For generation investment, FERC can reduce barriers to entry. Order 888 and order 2003 took enormous strides in that respect. Some aspects are imperfect, particularly 888's reliance on contract path. Nonetheless, discouraging interconnection discrimination has been a fundamental step forward, and they can continue to do more there. They shouldn't be telling generation when to invest, where it should be located, in what amounts, and what fuel type. It's not their role. Providing information is the more important role.

Sending the right price signals ensures the right investments. Currently, these signals are not correct, especially for long term investments. They need to reduce barriers to people in the market. They can't create perfect markets because there's not enough information. There are plenty of 100 page briefs that cite nothing

than views or assumptions about behavior, without any empirical evidence. This is a good reason to let different regions develop answers to these questions.

Markets have only been operating for less than ten years, that's not much time. One area of improvement for FERC is when there is a solution that is difficult for the public to accept. Things like scarcity pricing are hard for the public to accept right now. Regulators can provide leadership through education. Leadership is not shoving things down people's throat, but educating people about the harm that comes from certain types of poor market designs.

Speaker 4.

For several years at NARUC [National Association of Regulatory Utility Commissions], members just couldn't talk about the regulated versus market debate. There was too much emotion in it. They discussed efficiency and demand response, and not markets.

Good market design is a critical challenge if investment and operating decisions are to be driven by market forces. A study from Cambridge Energy Associates surveyed utilities and found a belief that investment will shift back toward the regulated side of the business with a concentration on controlling fuel risks and leveraging new technology. Why do utilities believe that?

People have lost patience in addressing market issues. They don't see markets working. Of course, it's hard to assess because they can't be compared to anything. We don't know where prices would have been if they hadn't been in place. There is a concern about whether or not generation will be built, and what kind of generation it will be.

Let's consider the Illinois situation. The citizens utility board and the Illinois AG and the building owners have appealed the auction plan. They allege that the auction will produce a rate

hike of at least 22% for consumers and windfall profits for utilities. Further, the citizens utility board is urging law makers to extend the current rate freeze for three years or until real competition develops for residential consumers. Of course, real competition can't occur with a rate freeze. The Illinois attorney general argues the rate increase should be coupled with regulation and that reasonably priced electricity should be based on the cost of producing it rather than market cost. These rate hikes quickly became a campaign issue, and both candidates for governor have come out against them. Nobody there supports the market, and the attorney general is suing

In Virginia, commissioners sent a letter to the governor warning that rates could rise and that competition for retail electric customers remains virtually non-existent. The politicians in these situations are as active as the commissioners.

So, if regulation must replace markets is the best approach to muddle through or to adopt a new regulatory strategy? Alternately, where market support exists, how can regulators make modest corrections without undermining the market? Many of these decisions are now being implemented by politicians. There are a lot of recommendations for rate freezes and deferrals. This includes the use of securitization to defer future costs. That is a dangerous way to deal with these problems. However, the politicians don't know what else to do.

Experts need to talk to the politicians and educate them on other options and the consequences of freezing rates. The potential exists for states to re-regulate. There are costs associated with doing that and limitations, such as constitutional protections against taking. Politicians and their constituencies need to know the costs and risks of these options.

Speaker 2: I'll make a comment relevant to the political concerns that have been discussed. In 1997 the retail rate in Massachusetts was 13.5 cents a kilowatt hour. Rates had gone up every year for seven years before that. There was controversy over the cost of the Seabrook nuclear power plant. In 2006 dollars it cost

about \$7,500 a kilowatt under cost of service regulation. Politicians were under tremendous pressure to find an alternative to traditional regulation and that provided the incentives for restructuring.

Cost of service regulation, at least in many states, had some bad outcomes that generated a lot of political controversy. The rise in natural gas and wholesale electricity prices are causing reaction in the other direction now. Politicians respond to the current concerns of the citizens but a good regulator has to take a longer run view. They need a vision for the system that will provide the lowest cost and best quality service for consumers in the long run.

This can be regulated model or a competitive model. However, it is more challenging to have a mixed model, especially one that keeps being changed as underlying economic conditions vary. Massachusetts rates went up almost 50% in January of 2006, and natural gas prices went up almost 200%. There was surprisingly little reaction from consumers. The reaction was from politicians but for consumers it was a pretty big yawn.

Question: I want to discuss the market clearing price issue. Natural gas is no longer \$2.30 or \$3. Market prices now are screaming for investment of 1975-era coal plants. These can be built in the southeast but not the north. Low cost technology is not yet feasible. The existing 1975 coal plants are raking in the cash but the market can't respond with anything less than a new gas unit because of environmental regulations (which deserve strong support). What is the way forward?

Speaker 2: This is a problem with New York and New England. You're absolutely right. A super critical pulverized coal plant meeting new source performance standards in New York city would have cleaner air coming out of the stack than going in. [laughter] However, these can't be done in the Northeast for political reasons, under regulation or competition. If the only choice is to build natural gas, windmills, other renewables, demand side management, or

conservation, they will have a higher priced system. This comes from siting and environmental political constraints, not markets.

It's also not a problem with a uniform price system. I fundamentally disagree with this. We had this argument ten years ago. Consider any commodity. For instance, natural gas is produced from cheap land-based wells, cheap off-shore wells, deep wells, etc. There's a market clearing price for natural gas every day, every hour, every month, it's one price. Wheat farmers get the same price if they have a large productive wheat farm or a small little wheat farm. It's a market. A market price indicates the value and cost of electricity at every point in time. Having a market differentiated by fuel type is difficult. It can be done under regulation but nuclear and coal plants don't just pay \$20-30 a megawatt hour for fuel. Capital costs occur under a regulated regime. In a competitive regime, economic rents earned during high demand hours pay for those capital costs.

The Seabrook plant in Massachusetts were very expensive even though there were disallowances. The fuel costs weren't high but the capital costs were very high.

Question: Whether price spikes are due to capital costs or fuel costs, there's always going to be a political context to address. In New England there is still momentum for the choices provided by a market.

However, siting is still a problem. What would help rationalize siting across the different states? Massachusetts and the Atlantic corridor are considering siting wind and LNG facilities in the ocean or off shore. This is appealing because it's from other abutters. However, there is a public good there that is not accounted for in current statutes. One speaker mentioned \$1,000 that is paid to a private landowner to rent his land for a windmill. On the ocean there's no rent associated with that, although the new deep water port act may allow governors to weigh in.

So the first question is about the siting process in general at the state, regional, and national

level. The second question concerns siting in coastal regions and trying to rationalize the public good with FERC authority, the Deep Water Port Act, and state and federal jurisdiction.

Speaker 4: In the Midwest, they formed the organization of MISO states to work through siting issues and cooperation. There's an attempt to harmonize state laws, have governors come together and sign a cooperation protocol. They're waiting for an interstate transmission line to practice on. With the new federal backstop states don't want to give up authority. They will make every effort to get it done so that it won't go to the FERC.

Speaker: There is a difference here between a competitive market and a regulated system. In a regulated system if utilities get approval from the state commission to proceed with a project but then it gets blocked after extensive efforts, they will get some money back in the rate making process, depending on what the rules are in the particular jurisdiction. This is whether it's a coal project or a new transmission line.

A merchant investor coming into New England will have a long fight to get siting authority. There is an 80% chance that they won't. It's a dry hole and they lose all of that money. The incentives to push hard in a merchant framework are less than in a regulated framework. There are some rare success stories. The DC interconnection from James Bay, Quebec went through three difficult states: Vermont, New Hampshire and Massachusetts. However, they gave out a lot of fire stations along the way. [laughter]

The energy policy act of 2005 has provisions for nuclear power that provide insurance for regulatory delays in that system. The first sets of plants will be eligible for production tax credits. The rationale for this was because there would be a very uncertain regulatory process for approval. Somebody needs to pay for that and investors certainly won't.

Speaker 1: The Southeast has no substantial problems siting transmission or generation. This is probably because it's a traditionally regulated framework. They also lack some of the environmental activism that exists in California and the Northeast. That problem could exist even in regulated states. The cost allocation issue is also a concern. If the cost allocation problems are solved, at least with respect to transmission, it's easier to site it. It'll be a lot easier to get infrastructure built if payer and beneficiary questions are answered.

Question: One speaker discussed educating the public about things like scarcity pricing. That's like saying, "if we can just convince people to take their medicine, they'll be better in the long run." However for those in restructured states, they see Commissions publicly proclaiming how happy they are that they didn't restructure. There are 33 states that don't have to take the medicine, and seem to be doing better than those who are taking the medicine.

Another speaker noted that electric plant investment seems to be moving towards regulated states. I'm concerned that industrial investment is too. States originally thought restructuring would create lower rates and attract industry. Instead, it is another drain on their economy. Industrial customers may choose to shift production or build their next plant in Arkansas, Kentucky, West Virginia, or Iowa, rather than Pennsylvania or New York.

Speaker 3: I agree completely. These are not easy tasks but there's no other choice. As restructured states go forward and get more experience maybe it'll get easier. For instance, it's become clear that there's no free lunch in the resource adequacy issue in RTOs. It will be some form of scarcity pricing and demand response with occasional high prices or a capacity market which is expensive too. It's an incredibly difficult task and it's going to take upwards of ten years.

Speaker 1: There is another option. It's not either the existing paradigm or going back to

traditional rate regulation. We need to explore some alternatives and think out of the box.

Speaker: Scarcity pricing isn't the problem. We have scarcity pricing in natural gas markets. Consumers are concerned about the sudden fly up in wholesale prices. The size of the increase has been exacerbated in some states by years of frozen rates. They didn't respond to changing market conditions.

Should we re-regulate the natural gas industry? The government regulated natural gas fuel prices from 1956 until the 1980s. Market prices went from \$3 to as high as \$15 an MCF last winter in the northeast. That's an increase of 500%. Yet there's no clamor to re-regulate them.? Are consumers happy with natural gas price increases? No, they accept it as a market outcome. There are occasional concerns and investigations about market power, but that hasn't become a rationale for re-regulating. It's a market clearing price. Natural gas prices drive prices for electricity. The reaction in the electricity sector occurs because it remains only partially deregulated and both consumers and regulators in some states haven't accepted a market paradigm where prices go up and prices go down. Market prices have gone down and may go up, or down a lot in the future. It's a different paradigm.

Speaker 1: Electricity is not one commodity. It's produced by multiple fuels. You cannot compare it to gas, wheat, soybeans, or pork bellies. It's comprised of multiple fuels, it's not one thing.

Speaker 2: I disagree. What matters is not how it's produced, it's what the product is. We produce natural gas in different ways using different technologies with different costs. An MCF of natural gas is an MCF of natural gas. A kilowatt hour of electricity is a kilowatt hour of electricity. The fact that they're produced with a variety of technologies is irrelevant from a market perspective.

Question: What are the implications of an electricity market subdivided by fuel?

Speaker 2: It wouldn't work. Why would somebody who has a low cost plan, unless you were going to regulate them, be willing to sell at below the market clearing price? This discussion occurred in California, New England, and New York ten years ago. People created market models and demonstrated that it doesn't work.

Speaker 3: We are having the debate again for several reasons. Ironically there is a lot of regulation in restructured and deregulated markets. When things go wrong, or there's price spikes in the Midwest, they inevitably point to the government. These issues require constant explanation.

Speaker 2: I agree, but it's true with other markets as well. Every time there's a gasoline price spike because world market prices go up, or there's a refinery outage in some region, or a pipeline outage, everybody's outraged. The FTC is called to do a study. They do it and report they can't find any violations of the antitrust laws. By the time it's done, gasoline prices have dropped. Certainly it's a burden for people in political life but nobody has come back and said we should re-regulate gasoline and crude oil.

There are imperfections in regulation, and also a need for empirical evidence to support these things. Neither FERC nor the EIA has made that as easy as it might be. The DOE did a report a couple of years ago about the information FERC collects on transmission investment of different types, and on transmission performance. They maintained that the data collection efforts were inadequate. There's been no response from FERC in terms of increased information collection.

Similarly, FERC created a state of the markets report for 2004. It's a great report, I use it all the time, it's great for explaining things to people. I look on the web and the analysis and reports are not there. It's very hard to be a good regulator without having an analytical capability to do analysis and extensive empirical evidence. Is FERC trying to do more in this area?

Speaker 3: They could do a better job. The markets are supposed to generate some information, and FERC is meant to help in collecting it.

There are different regulatory and political pressures between electricity and natural gas however. Changing regulation in natural gas or oil requires 51 votes in the senate, 218 in the house, and Presidential support. In electricity there are just five poor FERC commissioners sitting on the 11th floor and a 206 filing that calls for just and reasonable prices.

Speaker 2: That's a fair point. They have not gotten support from the current administration or Congress needed to do a better job.

Question: The absence of a stable paradigm whether market or regulated is a concern generally. In terms of different fuel sources, a vertically integrated utility could use RFPs and an IRP type process to procure a specific fuel plant, say coal. They could use an RFP to seek the best priced coal plant, it would include the capital cost. This compares coal to coal. In a clearing price model, there would always be differences in fuel sources. It's not simply gas, coal, nuclear. There would be different types of coal and the regulators would have to decide what gets grouped with what. It would create new sub categories with great difficulties. The model, would constantly have to change and create ongoing uncertainty.

What if regulators changed and lowered the clearing price for coal in a coal only market? Those who bet on solid fuel are making a lot of money compared to those who invested in natural gas. However many of those plants have been sold and that's now in the price. Changing the system in this fashion would put an amazing damper on any kinds of investments. It's tough enough getting things built right now and changing the system in this way would discourage almost all investment in the markets because of regulatory uncertainty.

Speaker 2: Stability is important for investors. Regulatory holdups and constant reforms are a

major impediment to investment. FERC accession to the New England capacity market was good because they didn't fiddle with it. The pieces sort of fit together, it wasn't perfect, but it was pretty good and represented a compromise of many interests. Hopefully they'll leave it, let it work for a while so people can depend on it.

Speaker 1: Differentiating clearing prices for fuel type or layer of the load curve could be a temporary transition to a more traditionally regulated system. Two thirds of the population lives in the 17 market states. I have concerns about the national economy and for poor consumers dealing with high prices. We can't maintain the status quo.

The focus should be reliability and reasonable price. I'm not sure a capacity market is going to get anything built. Ensuring a responsibility and obligation to build is critical. We need more solutions from policy actors so the decisions are not political ones.

Question: Some comments. The increases in natural gas and electricity prices are very real. There has been some real success with the wind power, even in the markets, and even despite siting problems. Since markets opened up, 92% of everything built has been natural gas. Only one 400 megawatt coal plant has been sited in the southeast. 85,000 megawatts of capacity need to be sited in the next years, and in our area there are zero megawatts in the queue. There are many risks. The CO2 issue, a carbon tax; who would move to coal given these concerns? Nuclear is on the table. That's very uncertain. We can't run steel mills with windmills. Given all these various factors, how do we get to that optimal capacity mix with the current markets?

Speaker 2: I don't know what the optimal mix will be. The future price of natural gas or a carbon price ten years from now can't be known. Nobody knows this. The movement to natural gas combined cycle during the late 1990s and early 2000s can't be blamed on deregulation. Every utility plan had combined cycles because natural gas was cheap, was perceived to be cheap in the future, and was

much easier to build under environmental constraints. The plants were clean and had high thermal efficiencies.

No one knew the prices would get as high as they've evolved. It's very difficult to build coal plants in the Northeast but that was true before they restructured. That's the burden that citizens in these regions have decided on. If market performance continues to improve, it's better to have investors making judgments about future fuel and CO2 prices will be. Their decisions certainly won't be worse than government entities or regulated firms.

Expectations change constantly. Outside of California, New England, and New York, every plant announced in the last two years is a coal plant. That reflects economic expectations for the fuel, and expectations that a CO2 cap and trade program will allow existing plants to be partially grandfathered with free allowances. This creates incentives for those plants.

Question: Will coal plants produce more cheaply than gas plants on the margin?

Speaker 2: Yes, if we don't have a CO2 charge. If we do have a CO2 price high enough to stabilize global emissions then coal will be uneconomical compared to natural gas by 2050. At least in some regions of the country and certain countries. \$25 a ton for CO2 is about the price needed. That's as high as the European CO2 price went last year. It decimates coal. It has a very negative effect on coal. Nuclear plants look great in a CO2 regime. How does a nuclear plant get built in a competitive market environment? Much more stable markets are needed for that.

Question: Actually my question is reversed. Do you anticipate single price auction market prices coming down to the coal price?

Speaker 2: It depends on where. In some regions like the Midwest the price is the spot price of coal during off peak hours. The more coal built, the more hours it would be on margin. In New England they're on the margin with gas and oil

for 85% of the hours. A few thousand megawatts of coal and nuclear would be needed for them to be on the margin a significant number of hours. That's why it looks so profitable to build a coal plant now in New England but it doesn't resolve their siting issues.

Question: If the auction single price were to decrease would consumers concerns about markets dissipate? Are objections mostly coming from high prices?

Speaker 4: Yes. It's hit in the markets, and it's going to hit in the regulated states too. It's a question of when and how. It's hit the markets first and that makes consumers question the model.

Speaker 1: The disconnect for consumers is not just the higher price. It's also the fact that the price doesn't reflect the cost of providing the service plus a reasonable margin. It's not just about price, it's about ensuring new generation gets built. Unless capacity markets prove effective, the only way to assure a fuel diverse mix of generation is the traditional regulatory model. Perhaps states with retail competition can bid out the obligation to construct different fuel type plants. It's all of these things.

Speaker: It's ironic that there's a new found love of the nuclear power. Most states that restructured did so because of the QF costs in the nuclear. They didn't want to pay capital costs. Power was trading at three cents and new entry was three and a half cents. When average costs are above marginal cost deregulation looks great. When it flips it looks bad. In ten years it's going to flip again and people will start looking to restructuring again. Stability in regulation is very important and we need to weather the storms.

Question: In the competitive context, the primary concern for green energy suppliers in some areas is not price but adequate supply. They can't get enough of it to sell to their customers. Primarily this is because of siting issues in specific states. These occur with green electricity in New England, coal generation in

New York, transmission in Wisconsin – the Arrowhead line took 30 years. Even with FERC's new siting authority, some people believe it's a tool they will rarely or never use. Can FERC or NARUC do more for these siting issues?

Second, if the RPS isn't such a good model for green electricity, what is the best model for states? What's the best way to integrate environmental global warming concerns with markets or regulated design?

Speaker 4: In terms of the siting issue, my new favorite term besides NIMBY is NIMTOO; not in my term of office. [laughter] Many politicians make their careers running against infrastructure rather than for it. We need to educate that group to get infrastructure built, not stop it. There haven't yet been a lot of consequences of stopping infrastructure. The industry is good at doing workarounds and patches. If there are consequences then there will be far better circumstances.

Speaker 3: FERC backstop authority may well not be used and if that's the case the system hasn't broken down. It's there as there as a backstop. If it is needed they will use it, they will act if necessary.

Speaker 2: The best process to promote environmental improvement is to place a price on SO₂, NO_x, and CO₂ emissions. There is already a price on SO₂, and New England has a price on NO_x. There isn't a CO₂ policy at the national level but California's is evolving, and there will be one in New England. That's the best way of internalizing environmental externalities.

Second, money is needed to get these technologies down the learning curve. The best way to do this is via production tax credits which are in place for renewable generation. While this provides some subsidies it does create real production. That's a desirable feature if you have to have a subsidy program. I'm resigned to RPS programs because they are popular. In that

case, we need to make sure they work with the markets and there are good examples for that.

It may be unfair to dump these siting problems onto state and federal regulators. We need more leadership at the executive branch in the states and the federal government. The NIMTOO problem is important because these facilities take time to permit and build. Better leadership would provide an important educational role for consumers. Let them know that electricity doesn't just come out of the wall, it's got to be produced and transported in specific geographic locations.

Moderator: There is a difference between state commissions and FERC. Siting in your constituent's back yard is hard. Constituents are not localized at FERC so it's easier to site gas pipelines and LNG terminals because the commissioners don't feel the personal pressure that legislators who represent the people in a district do. That may be a good thing. Certainly some think they should be more responsive to pressure. It is about leadership at the local level. Moving it up so that the decision maker is a little more insulated can help. People won't necessarily think it's the best solution to the problem though.

Question: There's a fundamental problem separating Arkansas from Massachusetts – and I'm simply using these states as proxies. There's an underlying assumption that there's a cost of service number and a market result for defining rates. Generally, the assumption is that markets would be a higher number than cost of service. Yet economic theory fundamentally disagrees with this. If you add up the market clearing prices for energy and ancillary services and even capacity markets it would equal or be less (but not more) than the cost of service number in a regulatory regime.

Consider the credit mechanism for how high the capacity payment could be to make up for the missing money. The total cap on revenues that generators can receive from energy markets, ancillary service markets and this limited capacity payment is capped at regulatory cost of

service. These market prices will be less than cost of service, or at least captive debt.

Given that these prices are so similar, how do we get everybody on the same page of something so fundamental? We have to because regulators in many states are being fired, intimidated, or bullied by demagogues on the political side. We've need a regulatory system that can allow us to face reality, and ensure that everybody understands it.

Speaker 1: If the economic theory you just espoused is in fact a truism then why aren't we seeing it? If it's possible then we need to fix the market design so that markets are producing the same or lower prices than cost of service. I'm not seeing it.

Question: Yes, one would expect lower costs in Arkansas and higher costs in Massachusetts. If Massachusetts were entirely regulated at cost of service, their prices would still be higher than Arkansas because of extensive resource, fuel type, and cost differences in the two states. We have to compare Arkansas with markets and Arkansas with regulation. The same for Massachusetts. These comparisons are not happening.

Speaker 1: The disconnect is between what consumers think they would be paying under cost of service versus costs in the market regime in their own states. Market prices are substantially higher, at least in some states, than the true cost of service. Folks whose rates have gone up dramatically once price caps and rate freezes have come off are dismayed. There is a very large profit margin for some generators in unregulated markets, especially nuclear and coal plants. It doesn't look to me like they're paying cost of service.

Speaker 2: Your statement about economic theory is correct in the long run. In short run it's not because you're starting with a pre-existing system. Envision a state filled with dirty 40 year old coal plants that are fully depreciated – the cost of service there is very low. That's not an economist's notion of costs but it's a regulatory

notion. A scenario in which prices in a market based state where this regulatory hedge doesn't exists leads to prices that are higher in regulated states than in unregulated states.

However, your point about comparisons is important. In 1997 the regulated generation component in Boston was seven cents a kilowatt hour. If you adjust that for fuel prices and inflation, that would now be 14 or 15 cents a kilowatt hour. However, the competitive market price is lower than that now and it will probably be even lower going forward because there are lots of capital costs that are no longer paid for in the new system.

The focus on short run rates is too narrow. It's a political focus but a more complete assessment would include construction costs, increased system efficiencies, better contracts for industrials that match risk preferences. Massachusetts has 85% of the industrial load in the competitive market and they're not complaining. They wanted the system. We need a long run view. People have forgotten the overruns on nuclear plants and ridiculous QF contracts and other attributes of regulation.

Speaker 4: I have some quick comments. The political focus is the one that appoints the regulators, so we need to be aware of that. Second, people were not complaining about natural gas prices because warm weather saved us from real backlash and cost deferrals. Finally, I've heard the industrials complaining, I don't which ones are not.

We do need to capture efficiencies, use demand response, give people tools to work with as well as educating people in leadership positions and emphasizing the importance of infrastructure.

Question: Some distributors that go out to contract bilaterally are seeing contract offers based on forward gas price curves. The gas market is directly affecting price formation in the electric markets. When I read that 32 year old hedge fund operators are losing \$5 billion in a week I can't help but believe that speculation is having a marginal impact on prices. There

needs to be more attention paid to natural gas price formation to ensure market fundamentals, and not manipulation are setting that price.

Ten years ago when the deregulation conversation was held, the single clearing price paradigm was promoted so that marginal generators could collect their costs of operations. There might be a very few hours in the year when they had to recover their fixed costs. That's not the situation any more. Generators are taking no risks, and making huge profits. They're not taking those risks in the future either. That's why we're going to have capacity markets. It's not clear why we will have a single clearing price and also a forward capacity market. We need to have these discussions again because the original arguments aren't holding up.

It's unclear whether the capacity market mechanisms will create needed generation investment. In the regulated environment, if you have an obligation to serve you're going to get new generation. They may be costs overruns or problems but it is certain. We need that certainty in the capacity market.

Speaker 2: We don't know how well capacity markets will work. Prices go down, they go up; it can vary over time. The capacity markets are designed to work with a single market clearing price. For natural gas there's no mandatory ISO market but there's a single price available at any hub at any time because commodity markets work that way. The capacity market price is not a certainty. A new generator can lock in the price for three to five years, that's about it. There are still performance risks at the plants, if they don't perform during critical hours they don't get the money. If the plant is over budget, the cost overruns cannot be charged to consumers like the regulated model.

The markets have gone through substantial improvements in the last ten years. Policy makers are committed to the program. We don't need to re-argue old debates. That will increase uncertainty in the markets and deter investment. The biggest fear for a potential investor in coal

or nuclear is that they'll build the plant with capital cost of \$1,500 a kilowatt and it will produce electricity at \$30 a kilowatt hour. The concern is that a regulator will say there's no recourse for the \$1,500 a kilowatt, here's the \$30 a kilowatt hour for the fuel costs. If we start a discussion about differentiating fuel sources, it will destroy investment incentives.

Speaker 3: There is an incredible educational leadership challenge. LMP was supposed to send the right price signals for transmission and generation to be constructed in the right places. Many customers are telling us that didn't happen and more hands-on command and control transmission planning and capacity markets are needed. The markets didn't deliver as promised.

Speaker 2: Many people did believe that capacity markets compatible with regional reliability criteria were going to be necessary. Further, others have long argued for regional planning in transmission and a robust incentive regulation system like England and Wales.

The experts had different views these things. Pity the poor regulator that has to listen to experts on all different sides. The Northeastern markets always had capacity obligations, they just weren't designed very well. Now they are moving forward.

Comment: I don't believe capacity market mechanisms will anchor new investment in large coal or nuclear plants. The need for those kinds of resources has been acknowledged.

Question: It's illogical to expect a low cost producer to bid close to its own cost when it knows the market clearing price will be higher. That's not profit maximizing behavior. On a behavior basis, a pay as bid system won't work.

If market bidding is gone and cost of service is implemented then everything should be dismantled on the generation side. Everything would have to be cost of service. Regulators would have to determine prices for independent power plants, even without jurisdiction. Everything would have to be unwound.

Similarly, going to a differentiated system is a concern. When the volts or current going through the lights is the same regardless of where it came from then a differentiated system is not possible.

I recently saw survey data from several parts of the country. It addressed residential customers, not C&I. It asked residential customers about the causes for electricity prices. Competition never made the top five. This is for residential customers, not their representatives, interveners, consumer advocates, or attorney generals. Further, when we consider industrials and electricity markets, the industrials have been leaving the northeast for 40 - 45 years. It has little to do with electricity.

Speaker 2: There are lots of pay as bid markets around the world but most people bid and pay close to a single market clearing price. The markets are less efficient and there's more noise. Europe has organized exchanges that developed voluntarily to provide a uniform market clearing price for people who wanted forward contracts and settlement mechanisms to trade against. If the system goes to pay as bid, there's no benefit in terms of lower prices and there are substantial losses for managing congestion and pricing ancillary services.

Speaker 1: Some economists have examined the pay as bid approach and their modeling showed that consumers would benefit. The system could work and save money compared to the single clearing price system. There's also some interest in the differentiated fuel. The jury is out on that.

Question: There are a tremendous number of questions decided by regulators and ISOs that move hundreds of millions of dollars around. These decisions are arbitrary, not in a pejorative sense, but in the sense that they're derived from a fairness principle or one person's idea. It's hard to have markets with that many decisions being made outside the market. Many of these decisions are related to uplift and reliability. Is this kind of distortion factor a concern?

Speaker 2: Having a market where the financial realizations can be dramatically altered by changes in regulation is a problem. Ideally regulators would leave things as they are unless there is a major problem. Regulators can learn from others. The UK model is the gold standard in regulation in a number of different ways. They implemented one major market redesign in 2000 after ten years. The current market isn't ideal but they basically have left it alone. They've done this so that potential investors are not concerned that large amounts of money will get moved in a random way. The continuing "reform of the reforms" creates distortions. One key issue is that the office of gas and electricity markets in England has a clear commitment to markets. They have greater confidence, and they let the market work out its wrinkles.

Here's an example from Britain. After the new electricity trading arrangements were created and price caps were eliminated there was a single owner of pump storage taking advantage in the market. Pump storage is a good ancillary service provider because it has fast responses. This supplier was bidding at \$100,000 a megawatt hour. The system operator complained to the regulator and the regulator told them to solve the problem; create more competitors or use an incentive regulation scheme. They worked out a deal with folks in Scotland and France to unload the transmission lines to allow for two additional competing sources. The system operator simply helped create competitive alternatives. Many of these problems can work their way out.

Speaker 3: There's enough difference in market rules at subtle second and third levels that cause the problem. Most of the focus is on the big market rules, getting locational pricing in place, etc. However, the subtle differences in treatment of uplift, defining uplift, and these sorts of smaller details make it difficult to ensure that markets work fairly and consistently. Greater uniformity is needed below the macro level where FERC usually works.

Comment: The problems in Illinois are derived from the reduced and frozen rates in place for

ten years. Even after the auction the just published market based prices are still below the regulated cost of service prices that were last set in a 1995 rate case. That is a good reflection on the market. Nobody likes rate increases. If they were having this auction two years ago it would not be nearly as big a problem. Fuel costs are driving up prices everywhere. Those coming off of rate freezes are facing dramatic percentage increases certainly. However EEI data shows that cumulative percentage increases are comparable in restructured states and regulated states over the last five years. Questions about resource adequacy, ensuring investment, and regulatory regime stability are more critical than the basic deregulation debate.

Comment: There are two challenges in this panel that need to be addressed. First, the industry does need to find new approaches. Second, regulators and others do need to educate people so there's better understanding of what the problems are.

The industry is not doing a good job on the first two. It's not thinking outside the box nor is it thinking through the logic of the arguments and where the arguments end up. If you don't know where you're going, any path will take you there.

The industry is not thinking about where it's going and whether the next step it's taking is going in that direction. That is a very serious problem, especially with these hybrid models. It's not such a problem in the fully regulated and fully competitive models but it's critical to address the reality of the systems we have.