Harvard Electricity Policy Group
Forty-Fourth Plenary Session

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RAPPORTEUR'S SUMMARY*

Session One.
Regulators: "Fired" with Enthusiasm.

Regulatory independence enables decision making in an environment insulated from political pressures. However, price volatility, adequacy of supply, responsiveness to customer demands, and service quality are issues never entirely removed from politics. The advent of competition was to have provided parties with market options that, in theory, at least, would reduce the perceived need to resort to politics. Recent developments in many jurisdictions have caused many to question this premise. Some might contend that the opposite has occurred, and that recent actions or threatened actions have raised questions about just how independent, or apolitical, regulators can be.

What happens if regulators make decisions that are highly unpopular? What about decisions that are displeasing to high executive or legislative officials? Some of those pressures are very public, and some hidden from public view. What is the tolerable level of political interference that does not interfere with the "independence" of regulators? How can political pressures, to the extent that they are being exerted, at least be made more transparent? How do regulators navigate in such waters? How might they best respond to political pressures? What are the implications for electricity regulation and electricity markets?

Moderator: It's a particularly appropriate time for this panel just a few weeks after the state gubernatorial and national elections that saw tremendous change. In some states, issues related to new coal plants and prices and discounts for low income customers became salient during the election cycle. Clearly, the sleepy regulatory agency of a decade ago that did things largely under the radar screen is a thing of the past.

Speaker 1.

I will discuss recent experiences at our state commission. Our state has five commissioners with staggered terms of three years. Three years is too short for my liking. Generally there's one commission with experience in telecom, energy, cable, or consumer affairs, and then one that's undesignated. The chairman is also chairman of the energy facility siting board. When people get appointed, no more than three can be from one party.

The recent chairman was a democrat but appointed by a Republican governor. The Chair

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

hadn't solicited funds for the governor, nor were they close on a personal level. Indeed, the Chairman had previous high-level (but still sub-commissioner) experience at the agency and was preparing to go into private practice but couldn't because the current chairman left before he did. In short, the governor's office offered him the job the morning after the blackouts in August 2003. Not only that, but he was appointed chairman of the agency in great part because of the politics of the blackout. The governor didn't want a vacancy in the chair of the PUC after a major blackout so he was confirmed with no preparation. The governor saw a need for a steady hand and recommendations were consistently strong. The appointment was made on a professional, not a political basis.

This is a restructured market and issues such as fuel diversity and many others have become extraordinarily contentious. My conclusion is that one wants to be in one of two positions to be a state regulator today. One wants to be on the up end of their career. Here, the commissioner position is a temporary waypoint and then one moves on. In this case, if somebody mandates an improper decision for political reasons then one can say no and be ready to leave. Or, one wants it on the back end. Maybe one has prior public service, you've made your money, you're at a good place in your career and you want to come back to public service. However, if you want to make a career of this in cycles of 3, 4, or 6 years, it's very difficult. There are political pressures that come from the previous record of the 3 or 4 year cycle. Everybody takes a pot shot, complains to the governor's office and makes a longer term commissioner a target.

In this case, the state's restructured market had capped rates for a seven year transition period. Around year four, about four years ago, they saw incredible fuel costs coming up. The discussion focused on the huge delta arising between the capped rates and the fuel costs. Companies were legitimately arguing that deferrals were going to hurt, They were suggesting carrying charges, an adjustment to the capped rate; a blended rate. This would have allowed recovery close to the actual price. During the hearings on this issue all five commissioners were on the bench and the attorney general shows up with 4 cameras in tow. He lectured them extensively on how anti-consumer they were. Nonetheless, they went back and did the right thing. They cut a deal that was as pro-consumer as possible but permitted companies to recover part of that money. However, the political maneuvering was extensive.

With regulatory issues you often can't prove a negative or a counterfactual. It's difficult to test whether an action was appropriate or not. In this case, you can create the counterfactual. If the commissioners had not implemented cost recovery, one could calculate the fuel costs differences, the deferrals, and spiraling effects due to credit ratings, and see savings in the millions of dollars. Although it was difficult at the time, that courageous action four years ago allowed the companies to keep building their infrastructure and not to go bankrupt. Ultimately, it was pro-consumer.

There is a vulnerable portion of our society that needs absolute care and need a targeted focus. So certainly the commissioners needed to focus on those low income families and do the best they can, but otherwise they let the process proceed. It was extraordinarily difficult. The governor stood by his commission and they proceeded. Everything returned to normal after a few days of headlines. So if you have the data one can cut a good deal in the middle. They don't have to be extreme.

I'll discuss a second politically thorny issue. This involved a very large offshore wind development. In this state the PUC is an independent agency, and the chairman is also chairman of the energy facility siting board. A vote required four in favor to have anything passed. There was a sophisticated and talented staff attempting to address a very difficult, first of its kind project with many pros and cons. Further, the governor said unambiguously that he was against the project.

Further, the jurisdiction at the siting board was not over the entire project. It was over the siting of the transmission line from the waters into the landfall contact point. However, this became the issue because if you ended the transmission line, you ended the project.

Ultimately, the process worked and the board approved the transmission line. The governor respected the process even if he wasn't happy at the end. That was difficult for three years. It was a grind where the Chairman's boss is reminding him publicly that he's against the entire project and he doesn't hesitate to tell you that. The Chairperson heard from many folks about the fact that they were unhappy about the final decision. However, it was the right decision as a matter of law on the record. To do otherwise would have been correctly seen as a political maneuver, and reversed on appeal. Some integrity in the process is critical.

The chairperson had only a year left in their term, and they were willing to move on. Perhaps that's why they were willing to take these political risks. However, it's more likely that they were simply following through with their integrity. Ultimately, one takes that characteristic to every job one has.

There is always a struggle with political appointees, the advocacy of policy, and the adjudication process. In essence commissions are a quasi judicial agency. One creative way to split adjudication issues and policy development is to have a separate division that focuses solely on policy development and which can be in the governor's office everyday. Indeed, that division can be in front of a commission, filing petitions with the agency, and advocating for the governor. This is a legitimate way to have the policy arm of state government making an argument at an independent agency.

Speaker 2.

This topic is timely given the shakeouts going on in terms of regulatory independence across the country due to high fuel prices and higher prices than expected. The appropriate balance between political accountability in the regulatory process and regulatory independence has been and will be important.

Complete independence is not to be desired. This is not possible in our system of political accountability. However, independent regulators should be above the day-to-day political fray. They need to call balls and strikes fairly like an umpire; based on the merits of a case before them. They need to be allowed to think intelligently about policy choices. This system is the backbone of our reliable and financially healthy electricity delivery system. The investment we have in the system is due to this.

Both the United States Energy Association and the National Association of Regulatory Utility Commissioners have discussed the need for regulatory independence to attract investment and create confidence in the system of regulation. This applies here and in other nations. The ideal is not complete independence but reasonable independence above the political fray.

What are the key ways to ensure a reasonable measure of independence? First, a sufficient and independent funding source for agency activities is vital. Policy makers and regulators should not fear that their funding will be cut if they render unpopular decisions. Second, a term of office is important. Having the security of a clearly set term allows a regulator to safely consider the right thing to do, what is in the public interest. Regulators should not serve merely at the whim of the executive or legislative branch. Third, they should be removed from office for only the most serious of offenses during their term. Corruption, fraud, dereliction of duty; certainly not policy disputes. Fourth, a key element of regulatory independence is clear and enforceable ethics rules with respect to gifts. These are ex parte rules that are applicable and enforced. It may be harder in developing countries to establish this sort of system, but it is important nonetheless. Fifth, a strong and somewhat independent staff with an advisory role is critical at an agency to serve as a counter weight to the strong influence of industry on regulatory bodies. Different elements of industry may have more sway than others in various jurisdictions. An independent staff can prevent some really bad ideas. Sixth, oversight by an independent judiciary. This provides regulatory certainty which in turn maintains a strong investment climate.

The electric power and natural gas industries are large and capital intensive. Fresh investment to maintain a reliable supply and infrastructure is needed. Independence and judicial oversight create a fair market and regulatory certainty needed for this investment. The ratings agencies focus special attention on these regulatory and independence issues. They followed the recent political debates in Maryland and Illinois very closely and took steps to downgrade utilities as the political climate became more volatile. This ultimately makes borrowing and investment more expensive, and increases rates for consumers.

For instance, India has struggled with the issue of attracting investment in their industry. Other developing countries have also. A key problem has been investment certainty. People don't pay their electricity bills in India. They call that losses, unlike the definition here of losses in the transmission system. The political system hasn't made them pay their bills for years but that is changing. It's hard for politicians to state they're going to increase electricity rates. India wants a system of independent regulators who have the political support necessary to make very unpopular decisions so they can move forward rapidly. This is critical to the future growth of their economy.

So number one, investments. Number two, consumer confidence. Consumers also want to know there's a level playing field on which decisions will be made. They want to know that agencies won't skew policy to unnecessarily favor the big boys. Regulators have to make very hard choices, often politically unpopular. Cost recovery is very controversial right now. It's front and center in market-based states where prices are higher than the political establishment wishes to accept; driven in large part by high fuel costs. There are also some regulated states in which rates have gone up almost 50% over the past five years. It's just as hard in those environments to flow through fuel costs because of similar fears for political backlash.

There are other difficult questions. How do you enforce state law? In Illinois and Maryland, they passed laws implementing competitive markets and also long term rate freezes. A regulator has enforce and implement these laws. On the one hand you have to implement the market but utilities have to recover prudently incurred costs as well. If a regulator follows through even though they are unpopular, and subsequently is fired, it sends a very bad message to Wall Street and its investment in the industry.

Regulators have to have backbone. Some decisions have large political implications, and a regulator will face extensive criticism. FERC mad a very controversial decision to remove Edward's Dam on the Kennebec River in Maine. They did the right thing but there was a lot of political backlash for it.

Similarly, when FERC was attempting to implement standard market design there was some political pressure for the commission to back off. This was probably appropriate at the time. They were in the wake of the California electricity crisis in which a home grown market design was an absolute disaster. FERC had voted for it because the entire California political establishment told them to. That was undue influence. Many of their economists were telling them that it would be a disaster ahead of time. They approved it anyway because it seemed to be the right thing to do politically. And then the prices exploded. FERC realized that a home grown wholesale market design was a problem and tried to figure out how to standardize the rules. Experts thought that was a wonderful idea. However it was politically unpopular at the time. Ultimately, it was defeated, but not on the merits.

What are the appropriate ways for the political establishment to influence independent regulators? First they can change the law. Second, during the important appointment process there are legitimate efforts to shape the decision making of new commissioners at state and federal agencies. Third, oversight hearings can be an suitable mechanism. Fourth, meetings with legislative or executive branch can be proper if ex parte concerns and transparency are addressed.

Firing an entire commission by legislative fiat or firing a chairperson because the way they implemented a law is absolutely inappropriate.

Question: One of the reasons regulators can be removed is dereliction of duty but that term has been thoroughly misunderstood in the Illinois context. What is your sense of this term?

Speaker 2: It does not mean a policy choice that goes against the grain. If a regulator considers all the arguments, makes a choice, ascertains the facts, determines a policy direction, particularly if there's a clear state law, there's no way that's dereliction of duty at all.

Dereliction of duty is not showing up, not voting, or having some serious personal or emotional problem that affects your judgment in a way that you can't do your job, It can also mean corruption.

Speaker 3.

I'm going to discuss these issues from the perspective of regulatory politics in New Zealand, a rather isolated country. It's a country the same area as Colorado, only about 10% bigger than Oregon. It has a population of just over four million people. It's long and stringy. If it were in the US it would stretch from the Mexican border almost to the Canadian border on the west coast. There are two islands and it's not very close to anything else. It's about 1,300 miles from the east coast of Australia. You certainly can't interconnect electrically.

The government of New Zealand three years ago decided to set up a new position for an electricity regulator. Previously they had attempted to have the market regulate itself. They charged the market with developing its own rule book and after a three year process that had failed. They recruited for a full time chair and a number of part-time commissioners. They often hire foreigners to head up major regulatory agencies because they have no political baggage.

They now have a staff of about 45 people. Their main statutory directive is to adhere to the government policy statement (GPS). It's a 30 page list of things the government wants done in the electricity sector and how they should be accomplished. This new electricity commission has a wide variety of powers. I'm sure a number of FERC commissioners would like to have some of these powers. However, the commission really doesn't hold these on its own.

New Zealand's market looks like standard market design on the wholesale side. The commission sets market rules for bidding and market clearance. It also sets system operation rules for stability. It uses an enforcement process that can go to an independent rulings panel if there is a dispute. They act as the RTO and use contractors to institute the pricing in the market, identifying customers, and doing reconciliation. Strangely, they actually own generation. They contract for dry year reserves because New Zealand is 60% hydroelectric on average. The market is not sufficient to provide for very dry years. The government has mandated that the commission guarantee sufficient electricity for a one year in 60 dry year. It's difficult simply to determine what that is

The commission does all the usual things around transmission. It sets grid reliability standards, transmission pricing methodology, and sets cost allocation standards for the state owned grid company. It develops a model transmission contract that becomes the default contract and determines the counter parties in the industry for that contract. Finally, they are tasked with improving transmission investments. They must approve every single dollar of the transmission

companies' investments in the system. They also conduct electricity efficiency programs through a public benefits charge.
Many of these actions are enacted not by commission action but through a recommendation to the minister of energy who then must make the final approval. For many of the technical rules, the minister simply signs off and that's it, but they can choose not to approve it.

One can consider a variety of factors that should be in place for an independent regulator. First, almost nothing that directs the commission is in statute. New Zealand has a single house of parliament with three year elections, no written constitution, no federal state system, and the Queen is the sovereign so she cares little about the New Zealand parliament. [Laughter] Policy can change rapidly from a statutory perspective and also in terms of the GPS. Second, commissioners can be removed at any time without cause. Third, commissioners have relatively short terms because parliament has only a three year term. The parliament is reluctant to give anybody else a longer term than themselves so it's typical for a government appointee in New Zealand to have only a two or three year term. Often these terms are coincident with the government's term. Each new government is in position to change everything that the commission had done. Finally, there is little transparency. The commission can talk with the minister or receive directions without anybody seeing it. The sunshine act in New Zealand applies only to documents and not to meetings or verbal communication between authorities.

Their Commission has a pretty high profile because of some controversial decisions. First, the concern for cost allocation for the high voltage, direct current link between the South and North Island. The commission decided the charges, about $80 million a year, should not be included with the postage stamp prices for the AC system, but should be charged to the South Island generators alone. This is because the link is primarily a south to north link; hydro generation in the south to load centers in the north. They wanted to create a locational pricing signal so generation would locate closer to load centers. The main beneficiaries were the South Island generators because they got access to the more lucrative North Island market. However, South Island generators lobbied very hard and argued this would preclude development of renewable generation in the South Island.

Second, they declined to buy additional dry year reserve energy. The government had bought a 155 megawatt single cycle generation plant for dry year reserve. Their analysis showed that sufficient generation existed, even though dry years had occurred in the three years previous. The news media were screaming crisis but their analysis showed there was less than 1% chance of running the reservoirs low. Some folks and politicians who weren't particularly interested in the analysis simply looked at the reservoirs and said, "oh, they look low." [Laughter] They created a crisis. The opposition leader in parliament flew down to the lowest reservoir in the South Island to hold a press conference about the crisis and how little the government was doing about it. Unfortunately it happened during a rain storm [Laughter] so it didn't get much play. The Commission got through the winter easily, there was no shortage at all.

Their most controversial decision was the denial of a major transmission upgrade into Auckland. The proposal didn't meet the least cost standard, for providing transmission into Auckland. It wasn't needed, despite claims to the counter by the state-owned grid company. Actually, real need occurred about seven years later, but in the meantime it saved about $250 million to consumers.

The controversial decisions caused the government to lose faith in the Commission. The only person in the government who supported market reforms that had been implemented by a previous administration was the energy minister. The Commission was established by that minister who is now the minister of health. In a country the size of New Zealand significant portfolios go to ministers with the capabilities to handle them, so sometimes they will have several portfolios. For instance, the minister of energy also held the transportation portfolio, the climate change portfolio, and he was the Attorney General. His attention was diverted to a wide variety of areas. Ministers change quite often, multiple times in a year. Some of them have less expertise or are inexperienced. Thus they may be particularly prone to heavy lobbying from losers. Winners very rarely lobby government. It's the losers who make the noise. Even though the majority of the industry supported the decisions by the Commission, the perception was that there was massive opposition to the Commission's decisions.

There is a perception in New Zealand that the electricity system is in dodgy shape, that it's weak, that it's lacking in investment. That's probably not the case. The system is reasonably good, especially in transmission. Investment is needed but not on a massive basis.

Thus, the government delayed reappointments. Some commissioners went 14 months not knowing whether they were going to be reappointed. They pressured the Commission to negotiate with the grid company rather than pressuring the grid company to obey rules and provide reasonable proposals. They wanted a negotiated settlement. However, such a negotiated settlement would not meet the rules. The government policy statement was altered to put pressure on the Commission. Ultimately, they appointed two former employees from the Gridco to the Commission, and finally, they sacked the full-time Commissioner.

There is a protective aspect to the statute that says that once the minister has approved the rules, they cannot be changed. So, the rules that require least cost investment are still in place, and how they can implement a new policy that can ignore these constraints is something the government is still trying to figure out. Until they stack the entire Commission with new loyal staff, they cannot move forward.

Speaker 4.

I will be discussing the difficult situation in Maryland. I'm assuming that most are familiar with the high level details of the Maryland debacle of 2006. Specifically the fact that rate caps were expiring and new rates were going to increase very dramatically. This has caused a political firestorm in Maryland. I'm going to address some of the lower level or less newsworthy items that demonstrate how political pressure is affecting policy decisions.

Maryland experienced a true perfect storm in 2006. A political meltdown resulted in the legislature making dramatic changes and interfering in unprecedented ways into the establishment of electric rates. Further, they tossed out the Public Service Commission three times so far [Laughter].

The reasons for this perfect storm are as follows. Rate caps were imposed as part of electric restructuring. For instance, one company's settlement in 2001 was 6.5% below the level established in their last rate proceeding in 1993. There was pent up inflation especially when fuel prices started to increase after 2000. The rate caps expired in July 2006. The rate caps were below market. Thus, there was no competition on the retail level. There was extensive legislator and public anxiety. Once the caps expired there were no competitors help mitigate price increases. Further, default service power was to be procured competitively through a market bid process. It would be at a market price. This was all part of the statute.

A third element. These dramatic increases would result in a 72% average increase to residential customers' bills. Just before the increases were announced, the parent holding company of Baltimore Gas & Electric (BGE), Constellation Energy, announced its intention to merge with Florida Power and Light. The FPL group merger would have been one of the first post PUHCA repeal mega mergers. This added complexity to the debate.

Fourth, Maryland experienced one of the most hotly contested elections in several decades. Surprisingly enough, the electric issue really was not a dominant issue in the election cycle, but rather only afterwards.

This story really starts in 2005, before any of this was on anyone's radar screen. In 2004 rate caps expired for distribution utilities. These details were established through comprehensive settlements that addressed the rate reduction amounts, how long they would be frozen, and also addressed the transfer of generation assets to affiliates or third party purchasers.

The first level increases for the distribution utilities in 2004 and 2005 were in the high teens and twenties. The commission began to recognize that when rate caps expired in 2006 for BGE there would be an extensive pent up increase. The Commission decided to get information about this reality out to policy makers to educate them about market pricing and the lack of development in the competitive retail market as originally envisioned in 1999.

In a series of Commission meetings in the summer of 2005 it became apparent that the BGE increases would be 30-40% higher, not 15-20% higher. Clearly these kind of increases were going to produce a significant degree of rate shock. They began informal discussions between BGE, the state's consumer advocate, and others about how to go forward. These meetings were critical not for what they did, but for what they did not do. Some of the Commission's economic staff had suggested phasing in some of the increases. The default service rates of BGE had a summer and non summer component, prices would reduce during the non summer season. They proposed a customer charge in October equal to the delta between the summer and the non summer rates. There would be no reduction in their electric rate for the coming summer season. The utility would hold the money and credit it back to customers when market prices came into effect. These deferral type plans that Maryland ultimately adopted and other states are considering have been characterized as credit card plans. It's like a savings account plan in anticipation of a rate sock; to mitigate a rate increase.

For different reasons both the utility and the consumer advocate were hostile to the concept. They were not being irrational. There were worries about whether customers would get their deferred money credited back properly. They were also concerned that users of electricity during the winter would be paying more than folks who use more summer electricity. BGE was concerned about administrative expense, and whether such a plan was really necessary. The plan was never implemented at that point.

Hurricanes Katrina and Rita hit very soon after. Now there was a problem. The lack of a phase-in plan, and the determination to simply finesse large increases became significantly greater because of the hurricanes. Energy supplies were significantly disrupted, in part because Maryland is very dependent on natural gas fired generation. It soon became apparent the increases would be in the range of 40-80%, probably above 50%.

It was too late to implement a deferral plan so the Commission continued to communicate with legislators. They also introduced a different deferral plan in which the utility would incur debt on behalf of the customers. Those discussions with the legislature didn't go very far. There is always a tension for regulators about how far they should go to push legislators to make policy decisions. The more deeply a regulator gets into advocacy for legislative change the more they run the risk of compromising themselves.

The Commission began auctions and bid procurement processes in December 2005 and February 2006. They came under serious criticism for doing this from those who thought they should have delayed the process. There were considerable tensions and political influences at the time. There are practical considerations for a regulator with this kind of a decision. They certainly considered whether to delay the bidding. In December, the storms were over, the story was horrible obviously, but load would still need to be served in June 2006. The Commission needed to move forward, they ran considerable risk if they didn't in terms of reserve rounds, and contract implementation. There was a lot less time than one might think.

The Maryland statute, and under most state's restructuring statutes for procuring default service, this is a voluntary process. They can't hold a gun to anyone's head and require them to bid in the Maryland process. Certainly regulators try to make the process attractive, reduce unnecessary expense for participation, and try to woo bidders so there's vibrant competition. Bidders expend considerable effort preparing the bid, understanding its obligations, determining their bidding strategy, and securing adequate capital or collateral. Canceling a bid runs the risk of scaring off potential competitors. The only reason to cancel the bids was to better time the market which is always a risky proposition anyway. At the time the geo-political energy market was also fairly unstable in any case.

The commission ultimately went forward with the procurements. The results were a mixed bag. They were successful in that there was adequate competition in every product type. Prices were in a close range which demonstrates vibrant, even aggressive, competition to win load. However, the price increases were dramatic to say the least. Simply put, the prices were not politically sustainable.

At the same time the merger discussions complicated matters. The governor's office and legislators were trying to figure out their position on the merger. Public perception had not yet solidified around it. Rate increase options, legislative responses, and the merger process were inter-related. The Constellation lobbyists were telling the governor's staff and the legislators lobbying against actions hostile toward the merger, they wanted a do no harm strategy.

The Commission could not say what the prices were going to be. During the auction period commissioners could not give detailed price estimates. They simply discussed the 40-80% range. Finally, legislation was announced after the price increases came in early March. The Commission, in response to inquiries from the governor, started a rate stabilization proceeding that would result in a deferral plan. They were concerned about not impairing the credit ratings of the companies. However, it also needed to be politically sustainable in terms of rates, and finally it needed to be competitively neutral. Other schemes ran the risk of undermining the 1999 act. There had been success in the commercial and industrial sector in terms of competition; there were no rate caps there.

The Commission adopted a plan limiting increases to 20% by establishing a credit charge component on the non bypassable side of the legislation. They allowed a short term debt rate. They allowed a recovery that some companies wanted to be much higher. The recovery charges were allowed to implemented in low use months. Subsequent rate stabilization plans followed that same basic model although there was debate about how high the increase level should be. 10-25% was the range, and there was debate about the interest on the deferred costs.

However, the merger situation was complicated with BGE rate stabilization plan. These plans relied on savings from the merger to help pay down dramatic increases. However, this put the Commission in a difficult position because the merger had not been decided yet. Constellation had significant market share in Maryland and the broader region. Every time the Commission considered ring fencing strategies for the merger, they reduced synergy savings which could theoretically be applied to the deferral plan. Further, many of these issues could not be discussed under ex parte privacy rules. It was difficult to reconcile the important public policy issues for rate reduction with the concerns for the affiliate relationships in the merger process.

In order to pursue the merger and provide savings, the legislature decided to fire the Public Service Commission. Lawsuits were filed and the state's highest court found in favor of the Commission. They are back at work, and the merger ultimately fell through. The governor lost the election. Finally, the legislature limited increases to 15% and made the issue disappear during the election. It made the issue disappear at least for now.

2007 is going to be even more volatile. The $400 million in merger savings identified in the legislation no longer exists because the merger fell through. Presumably the company is going to come back after the money but the legislation states the money must come from the company regardless of the merger. So there's $400 million that has to be addressed some way or another.

In addition the legislation set up an average $2.19 per month for a period of ten years. Just think about the policy implications. Electricity consumption in 2006 is going to be financed over a period of ten years. Customers in 2017 will be paying for electricity consumption in summer and fall of 2006. Now, the actual cost of financing that plan is probably more like $4.50 to $6 per month for ten years. It is a lot of money, and a lot to explain to consumers.

The legislature limited the increases to 15%. The other 52% is coming June one and there's no plan to address this for consumers. Further, the governor pledged to fire the Public Service Commission again. It's a very sad experience that Maryland has had and they face a much harder road ahead.

Moderator: I've been concerned about grossly inaccurate articles in the New York Times and the Wall Street Journal. How do regulators deal with the issue of public relations? Could panelists discuss the education of policy makers in the state and federal context? How much relative sophistication can be addressed?

Speaker 1: Recent regulators in our state had a lot of face time with the governor. I strongly suggest the use of PowerPoint. Lawyers like a nice two page brief but that won't cut it. A coherent ten page PowerPoint is best to get everything down to a manageable point. It takes discipline to do this. Sometimes you are lucky to get someone with extensive business, policy, and economic experience who can engage strongly in the issues. However, often they want cabinet and sub-cabinet members to be educated as well. There are two approaches to this issue. One is to say, "leave me alone, I'm the regulator and I'll make the decision." However there is peril in taking this approach. Alternately a regulator can attempt to engage successfully. This takes effort but one is rewarded by increased buy-in to the regulatory decisions that are ultimately made. An extensive relationship with legislators is better; it's hard to come down on someone when you just had lunch with them – there's a personal rapport. One can ask legislators to contact you directly if they feel there is a problem issue. It gives the regulator time to respond before their opinion is formulated.

Addressing the media can be difficult. Early in one regulator's tenure a story emerged that investment houses had a ranking that made him look friendly to industry. Here all one can do is to put together as much information as possible to address the story. It helps to disseminate information to the governor and legislature as well. You can't stop them from saying you're a lap dog, but at least you can respond to it effectively.

Again however, if you engage journalists, you usually receive a fair shake. Attempting not to engage the press will make things worse, it doesn't work. Unfortunately, complex regulatory work doesn't make for complementary sound bites.

Speaker 2: On a national level, lawmakers need to be regularly educated about what is being done. Some of it is counterintuitive and very complicated. The challenge is that the education has to be done in a private setting if possible. If it's done publicly in a public hearing, or via testimony, with TV cameras or in the public eye, it's really their show. It's very tough to have any sort of dialogue when the political stakes are high, like an election year. A regular routine education process for the executive and legislative branch is key so they understand what you're trying to accomplish. When a crisis erupts it's almost impossible to get your message across.

Speaker 3: The first energy minister in New Zealand would ask questions like, "should there be coincident peak pricing for wind or some other form of transmission pricing?" He was very knowledgeable, but he also gave their commission considerable latitude to make decisions. That was a superb situation but the minister changed 14 months later. Educating the appointing authority is very important. It depends somewhat on the degree to which the folks want to be educated.

Speaker 4: Public relations around a controversial issues is a double edged sword. It is certainly important to explain what is going on. However, a regulator runs the risk of appearing far too political. The more a regulator tells their story, the more that folks may attack them, and the more they are in the public eye, the more political they look. However, context is important. Many states have no control over the increasing costs of supply. Those are determined by market instruments, auctions, bid processes, but that is not the public perception. Public perception is that regulators are the overseer and they still have substantial control. They are blamed when the price increase is not politically acceptable. Regulators need to do a better job explaining to the public that they really don't control price.

Speaker 2: In Illinois over the past 18 months regulators have met with many members of the Illinois legislature. They're willing to meet, and discuss the issue of cost recovery of purchased power after a lengthy rate freeze. They understand it and they'll vote for the rate freeze extension anyway. They've got to do it. In these kind of volatile political issues they'll do that until it's very, very clear that the utility will go into bankruptcy if they can't recover their cost. They will vote to extend a rate freeze anyway, even though they understand it is a bad choice. It's difficult educating the political establishment about these issues.

Question: One panelist stated that complete independence is impossible. Further, they argued it's not desirable and they delineated legitimate and illegitimate ways to exert pressure. Is this problem worse now than it's been in the past, or better, or the same?

Second, is there something inherent about being a regulator in a market oriented system that makes this problem fundamentally different? Is regulatory independence harder in a market environment?

Speaker 4: I think conditions are much worse. In cost of service regulation legislators have this sense that it is very complicated. They stayed away from it; let the regulator take care of it. In a market environment they're more willing to get involved and sometimes they do things that central planners don't want to happen. They've broken an inviolate pact of interference with the regulatory process. Once they've shown they can get involved, whenever the politics are ripe, they become much more obligated to be involved.

Speaker 3: I've worked in Commissions during big price increases. At those times the political pressure is enormous. In my old state an ex-governor blamed the election loss on electricity prices, and the new governor immediately fired the head commissioner, who had done an excellent job by everybody's reckoning except for the fact that he had actually allowed prices to rise. This is endemic, it's not anything new. These kinds of decisions inherently affect the political process. Regulators have to learn to live with it; it's part of life.

Regulation in the market environment is particularly difficult. In New Zealand the state owned the entire electricity system and then transitioned to a full market in a decade. This is a fast transition. The public still has a high expectation that government will control prices. For instance in the seventies both gas prices and electricity prices were rising extensively but the complaints about electricity were far greater. The public doesn't understand that there are a lot of exogenous forces that drive up costs. The market design matters less for the regulators. The public does not understand that market forces create more volatility. They accept that gasoline prices, or the price of vegetables in the supermarket, will go up and down.

Speaker 2: This has been a hot issue for years. In the 1980s the hottest political issue in Arkansas involved Middle South Utilities building the Grand Gulf nuclear power plant in Mississippi and whether Arkansans ought to pay a percentage of the costs. Bill Clinton rode from being attorney general to governor of Arkansas on that issue. There's something the public thinks is unique about electricity.

At FERC the political uproar had a high decibel level during the California crisis and over the last four years. Prior to that it was quieter. There is a lack of understanding about the way markets work. When FERC first took major steps to markets, average costs were above marginal costs in general. Now that's flipped, and marginal costs are higher than average costs. It may flip again some time in the future but it's a dynamic that's not understood.

The mistake in moving to competition was folks who said it was going to lower prices. They didn't account for higher fuel costs and other factors that had to get passed through. The market environment is somewhat more challenging.

Speaker: This is not a new issue in terms of the political process and pressures on regulators. Second, market advocates underestimated the volatility of the commodity price. An interesting analysis is if you took a state and were able to compare it without restructuring versus what they have under restructuring. Obviously, keep the variables of the fuel prices and other variables constant. This would be an interesting counterfactual. For instance, if this were done in Massachusetts, it is very doubtful that they would have the 10,000 megawatts plus of new capacity generation they have now, or if they did it would have been even more expensive. When the term lower prices is used consumers thought it meant lower prices in absolute terms. The real question compares prices today in the old regime versus the prices in the current restructured regime.

In the restructured environment there's a lot more transparency. In the old days, a lot of these costs were rolled into base rate proceedings and they came out as one integrated price. In a market environment there are multiple targets to shoot at. Commodity prices are going up at the same time as minimal rate cases. A regulator is facing a 5% increase on a rate base of 12% but commodity prices are going up 20, 30, 50 percent. The public says do something about it.

Question: What are your thoughts on having a system with state wide elected commissioners versus commissioners appointed by the governor?

Speaker 1: In Oklahoma, South and North Dakota the Congressional seats are often held, so aspiring politicians go after the elected commissioner positions. This is where the action is. Raising funds for a campaign becomes a real issue. Unfortunately this often means raising funds from an executive in the industry that you're about to regulate. The appointment by the executive creates less opportunity for corruption or conflict of interest. The fundraising mechanism puts a strain on the process.

Speaker 3: There are 11 states with elected commissions, most of them in the south, a few in the west. My impression is that the quality of the commissioners overall is higher in the appointed commissions. There are certainly exceptions in both cases. The elected commissions tend to be large, and they have staggered terms. Elected commissioners have told me it allows them to do the right thing in non-election years. The staggered terms mean that folks who are up for an election can vote against a price increase and folks who aren't can vote for it. The system works. An elected commission draws a different kind of person to the job. But I don't know that it increases independence significantly for all the reasons that were mentioned about trying to raise funds and the source of those funds.

Speaker 2: Presumably, one wants commissions to be above the day to day political fray. If one wants them to make tough decisions, then election is probably a bad idea. Theoretically it doesn't make a lot of sense.

Speaker: I have a slightly different opinion. There are pros and cons to both. The advantage of an elected commission is that it gives the decisions you make an air of legitimacy. There is an outlet that customers, or those aggrieved, have if they don't like your decision. If they don't like the decision they have the opportunity to vote them out.

There is a concern for political decision making, that a commissioner will act in their own personal interest above the public interest. There is good and bad for each model. It depends upon the individual motives of the individual coming to office, their future plans, etc.

Speaker 1: Massachusetts considered having elected commissioners about five years. In fact, this was done as a way to put political pressure on commissioners for an unpopular decision they had made. They put that bill in the hopper. Ultimately the initiative wasn't going anywhere.

Speaker 2: A final point is that the reading and work load on the people at the commission is staggering. I would expect their work to suffer if they have to run around during an election season to get elected.

Question: In a competitive wholesale market there will be a lot of price volatility. It should be addressed by a demand response to that price volatility. That can only happen if loads actually see the price and volatility. Economic theory says that's great and an ISO would like that too. However, from a regulatory background, will it ever be acceptable to have customers see actual prices in the electricity market so that on that hottest summer day they truly know the cost of electricity? Can this go to the residential customer; how far do you think it can go?

Speaker 3: In New Zealand wholesale and middle level industrial customers do see that price. It's their responsibility to hedge if they've got a problem with volatility. Some customers have learned to hedge and others have said we're just going bare. Some have been burned badly and others have come off quite well. Over three years the level of sophistication about how to hedge has increased. What we need in New Zealand and other places is for someone to actively bid their demand into the market.

Speaker 4: My state is trying to make an energy only market with price caps increasing to $3,000. They don't think that's high enough, but that's as far as they can go at this point. Technology is needed at the residential level to allow them to respond. There are lots of dumb meters out there. As the technology develops, customers will become sophisticated enough to make decisions in concert with their retail electric provider. Some will expose themselves to that volatility, some will make a choice for a month to month, or a year, or even a five year contract. It will take time to let the markets mature.

Speaker 1: The governor in Massachusetts recently filed a petition with the PUC to address this issue. They argue the PUC has been slow to implement the next steps in market development because of pressures not to expose customers to volatility. There is potential there for matching the technology, and it's possible we'll see implementation soon.

Speaker 4: There's a lot of national interest and recognition that we need to do more in terms of conservation. We can create real energy efficiency if we empower customers to see prices. I'll make a provocative statement that competitive markets will get there sooner than regulated markets. Having regulators impose products, technologies, or offerings through a vertically integrated utility is not rigorous enough. Competitive ingenuity is important, and so is power to the people. Once the customers begin to demand certain innovations and services, supply has to respond.

Speaker 2: I'm not sure the average home owner wants that price signal or will know what to do with it. We don't know what the technological explosion in this country is going to bring over the next five to ten years. Technology and customer choice may bring real changes in this issue over the next few years.

Question: What is it going to take to get the next qualified set of regulators to act in the public interest? Are we on our way to a downward spiral? The industry needs regulatory courage, a steady investment climate, and regulatory certainty. What does the future look like?

Speaker 1: It looks good, for a couple of reasons. There were brilliant men and women before and there are going to be brilliant men and women in the future. I can assure you that. It really is about people. It's about the quality of the men and women you appoint.

Industry has a role in this. Candidly, there's two models that industry follows. One is to suggest to the governor that they nominate a candidate who'll be a good ally for the industry. Model B is to suggest a roster of 3-4 talented people who have extensive experience and who will fairly consider their actions. They're not extreme on either side of a position but intellectually they can handle the job, politically they're viable, and they've got a good reputation. That's how to sustain the quality of people. Industry needs to push hard for the nomination of smart, independent thinkers in the commissions.

Speaker 3: One of the most important things for keeping commissions independent is for companies to believe in independence themselves. They need to advocate for it with the political authorities. If companies run to the political authorities every time they get a decision they don't like, the governor only hears bad news about the regulator. They are better off saying we disagreed with this decision but it's very important this regulator be independent and be able to make decisions according to laws and the processes set out in law.

Further, independent regulation is to the advantage of a good politician. They can say I appointed these people to make decisions independent of a political process; they can get some distance. Smart governors never want to be associated with decisions of the regulatory authority.

Finally, if you have some freedom to do this as a regulator, you can speak out. For instance, when the government in New Zealand started interfering with the commission, and particularly after they made a decision that they wanted the Chair gone, he let the press know everything that had happened. It created an enormous stir. He had a considerable role in embarrassing the government. As a result they reappointed the other commissioners to show they were supporting independent regulation. Speaking out can have a very good effect as well, especially if the regulator has some career flexibility.

Question: Earlier discussion concerned regulatory authority over the distribution company but large price increases derived from the commodity price increases. In states like Illinois and Maryland, generation is owned by an affiliate. That becomes an attractive target for politicians whereas other states don't have that situation. The consequences of the politician's actions are more obvious in a deregulated state, and thus they are less likely to interfere. Is deregulation ultimately the way to end the political interference?

Speaker 4: It's a huge issue. In Maryland the legislators were seeking precisely that kind of information, because they didn't know how much market share affiliates were getting. The new legislation requires that information to be made public. In Maryland, Constellation won a whopping large share of the residential load. Further, how do you convince people that there really is a competitive market when BGE's affiliate is winning the overwhelming percentage?

Speaker 1: A regulated market allows for greater criticism of the process because of the appearance of self-dealing with affiliates. It's a bigger, easier political target. It's primarily public perception. There are struggles for commissions in a deregulated market. Do they use a New Jersey model for procurement? How active should they be in the RFP process?

Should they turn it around quickly if it looks right or should it receive extensive review? Obviously if there's punch list items that are missing then it requires a closer look but how deep should they get and what effect will the regulator have on that procurement process?

Let me add to an earlier comment. Timing the market is a dangerous proposition. When Katrina hit the Massachusetts commission had companies prepared to go to the market. Ultimately, they permitted people to hold off a little bit ins some cases but not by much. It's a tough political decision because Company X now has X price, and Company Y has a different price.

Speaker 2: If the affiliate is doing well in a market environment it complicates the debate exceedingly for lawmakers who are responsible to the political winds. The average citizen just doesn't understand it. It makes the politics of it even more volatile.

Speaker: Further, if the affiliate now owns generation and as part of the transfer of those assets the customers paid $0.5 billion in stranded costs. Now the affiliate is doing real well and they're winning the lion's share of the load. From a customer's perspective the fix is in.

Comment: I have three comments. First, in a period of rising costs you're going to have political problems. It's easy to be a regulator when costs are declining. Some have asserted that Illinois and Maryland represent the first time that a commission has been replaced. That's not true. It's happened in Tennessee, Alaska, it's happened different times.

Second, industry is in the governor's office all the time about what regulators are doing in contested cases. They express their dissatisfaction with decisions, they're constantly working the press to influence issues. If we truly want independence of regulators then we need to watch that side of it too. As a regulator I've always told the governor's office, if you call our agency about an issue I will talk with you about where we are in the process and explain the issues. However, if they start to tell me their expectations, I will put it on the record. I am always happy to educate the politician's about what's going on, but they have to respect the regulatory independence.

Finally, energy and electricity are expensive. My bills last month were $87 for gas-electric, cable $104, phones $150, etc. Most increases are portrayed as outrageous, people immediately claim that poor folk will have to choose between paying for medication or energy. We need to be realistic about the value of these utilities and what they cost. Rather than consider percentages we should consider the dollar burden for the average residential customer. That is often masked by percentages of what increases are.

Question: We've been talking about the reaction of politicians to public pressure about high prices. Even regulators during a time of declining prices still have highly politicized issues. One of the reasons that electricity is different is because utilities themselves are so expert at manipulating the political process. They politicized the process to survive. I'd estimate 80-90% of cases that became politicized when I was a regulator were politicized by the utilities who lobbied the legislature and the governor to get the PUC to do certain things. They are the same people that complain publicly about a process being too "political", it should be apolitical. However, we would also know the CEO had been in to see the governor to politicize the issue.

The business itself is so interrelated with government that both consumers and executives have similar expectations that it's a political process. The transition to a market is much more difficult because of the expectation that things can or should be solved politically. In dealing with legislators it's possible to let the commission be the foil. If a utility CEO visits the governor or the speaker of the house then you make sure that people opposed to the utility also visit them. Ensure the politicians know there are 80 sides to the issue and it's better and easier for the politician to let the regulator decide. The regulator plays the part of a dispassionate, disinterested expert. This is more difficult at the federal level because of regional politics. There isn't equal lobbying.

The politicization of the utilities can be strong. The first visit I had from a utility lobbyist, he handed me a list of names my third day on the job. He told me the governor has a lot of friends in our company and here's the guys who contributed to his campaign. The same lobbyist two years later complained that our PUC was very political. What strategies should regulators use to avoid these kinds of political issues?

Speaker: As a regulator, personal credibility with my legislature goes a long way. Relationships make a difference. Strong structure in the law is important also. The ex parte laws of communication in my state are strong and they make a difference. I'll get calls over administrative rule making or over policy matters but they can all be made public.

Speaker 1: This counter balance concept is interesting. Some entities are politically so savvy that they connect with a committee chairman or the governor's secretary to offer their counter arguments. As a regulator it's difficult to operationalize when to get in touch with entities you think should be involved, hey, you guys should go up there.

There are different incentives at the state level, in particular renewable technology and new players coming in. Their core mission is not to be at regulatory proceedings at the PUC but instead to be marketing, selling, closing the deal. When they are arguing about distributed generation or standby rates, they don't recover those rates and a utility does. The utility is going to be there a long time; they're not leaving. Some of the new technology types are not as active or don't have the resources to be as active. Another way they handle this is that a renewable technology entity will go to a utility to cut a commercial deal and then ask for an approval.

Speaker 2: The industry on all sides of a debate is very sophisticated about what they ought to be doing and who they ought to be meeting with. There's no secrets in Washington, everyone is aware of what the others are doing. I don't think that regulators have to ensure that all sides are getting a fair shake. Sometimes the private sector gets tips from regulators about what they should do but generally they have it figured out already.

Speaker 4: There's an imbalance of lobbying strength that we ought to acknowledge. The utilities are well represented in the political process, they attend fundraisers. The details of the dynamics differ slightly but overall access and influence is heavily weighted towards incumbents. In March of 2006 you couldn't swing a dead cat in Annapolis Maryland without hitting a Constellation lobbyist. The number of customer representatives probably could have been counted on one hand in the same period of time.

Question: We've probably got to move beyond some of the adversarial notions. Where are the common interests? What are some of the common grounds that help the public, the utilities and the regulators keep costs down?

Speaker 1: In New England there are compelling infrastructure development issues: wind, LNG, and more transmission facilities. These siting issues are highly politicized in terms of people wanting to be a part of that. First people have to agree on the problem as a first step. As they try to solve it you need to have enough moving parts: coalitions of utilities, developers, consumer groups, and environmental groups getting past litigation or trying to cut a deal they can all bring to the regulator. I do see that kind of movement there.

Renewable technology may provide an opportunity for new partnerships. There is a lot of venture capital all over the country starting to chase this stuff. There will be some good decisions, some bad decisions but there are new and interesting players going to the utilities and others to start relationships. The utilities are responding because it's part of an integrated solution to some of the demand problems. A governor can use the bully pulpit to send the message that stakeholders need to work together.

Speaker 3: It's important for the regulator to have good relationships with regulated companies; an open door and an open dialogue. There's always more that can be done if you only have the time. However, even a superlative dialogue will not stop a company from going to the political process when they are a loser in a decision. The losers just cannot refrain from running to the political process.

Question: A couple of things occurred with restructuring that were and are real problems. First, the benefits of restructuring were greatly oversold, industrials were pointing to eight cent rates they were paying in New York and saying we would all get two cent market prices. Rational folks who attempted to explain that differences were driven by technology, fuel prices, and interest rates were drowned out at the time. Second, price caps on restructuring at the retail markets have made things even worse.

Further, the industry has had bad luck in terms of commodity prices and timing. Natural gas deregulation occurred at a time of falling prices throughout the industry. We have very high gas prices now and people aren't up in arms, burning regulators in effigy – the market has been shown to work. In fact, electricity deregulation was premised on $2 or $3 gas which was going to keep electricity prices low. Now, we are in the worst possible place between the old world and new world.

Given all these issues, regulators have to take a leadership role to move forward. Many states will need new capacity just to meet load, never mind fuel efficiency or fuel diversity. Where will the investment come from? We have to rationalize the rules so investors can do it competitively or have a regulated utility decide to build an IGCC or a nuclear plant.

Speaker 2: Personally, I despair at the lack of courage at all levels of government these days. Regulators, with enough independence, can show courage. They can speak the truth, not just blow with the political winds. Try to look long term, have a vision and make choices that implement that vision courageously.

Speaker 3: The educational function is still critical; markets are relatively new in electricity. The public needs to be educated about how markets function. Regulators should be talking about that all the time. It's not going to happen overnight that the public starts suddenly accepting that we're making decisions by markets these days instead of by regulation.

Speaker: The regulatory house is very much divided on this point as well. NARUC has a very divided group of commissioners in terms of their beliefs in the efficacy of regulation versus markets. It's likely to remain divided.

Question: Are you talking across states or within states?

Speaker: More on a state by state basis.

Question: Well, you can have the regulated system or a market system at the retail level. Individual state can determine how they want to serve their retail load. We should be able to get by with differences across states.

Speaker: Perhaps, but the promise of markets is when there are a lot of counter parties on both sides of the transaction; multiple parties serving retail customers. There are many people that don't believe that.

Speaker 1: Even states that have gone down this path are revisiting it. This is reflected in New England with the recent forward capacity markets (originally LICAP and now FCN) approved by FERC. This was an example of regulatory courage; they came up with something new to address the demand curve issue. FERC gave those states time to come up with a solution, and they did. A little case study of people doing the right thing.

Session Two.
RTO: Fox or Hedgehog?

Electricity markets organize "coordination for competition." The seeming oxymoron arises because of the nature of the interconnected transmission grid. Physical operations such as transmission usage, real-time dispatch, and ancillary services require coordination with each other. These in turn integrate with a range of financial instruments such as financial transmission rights, day-ahead contracts, and longer-term hedging arrangements. These different elements of electricity markets share some common features, but differ enough to create real tensions.

Most recently the tensions are evident in the call from the PJM Board to rethink "challenges facing the electricity industry generally" and the long-term strategy for a Regional Transmission Organization. The core functions of system operations need to be performed, and, like the hedgehog, the RTO needs to know this one big thing and know how to do it well. Developing new and creative financial products and other services to support markets present many opportunities for innovation and experimentation. Like the fox, the quick entrepreneur will know many things and act rapidly to spot and pursue these market opportunities. The fox reaps the rewards and takes the risks. The foxes need the hedgehog, and the market needs the foxes.

Is it possible to be both a hedgehog and a fox? Are the skills and mind sets compatible? Can the structure, governance and incentive processes of RTOs support both activities? What are the realistic boundaries? What are the comparative advantages of different structures and people? How do we make them work to support innovation, preserve competition, operate under regulation, sustain efficient investment, and keep the lights on?

Speaker 1.

I'm going to focus on PJM's strategy initiative discussed in the session description. PJM's board asked for an analysis of what PJM is doing and what PJM should do in the future. There's considerable debate about how well the RTOs are working, are prices as they should be, etc. They wanted to conduct substantive analysis to get beyond the noise of various stakeholders. It wasn't an exercise to justify something already preconceived but rather to really get a sense of how well they are fulfilling the mission.

First is the real time energy market based on a least cost security constrained dispatch mechanism. That mechanism issues instructions to demand responders and generators in the market every five minutes. These are electronic control signals for the marketplace. The majority of responders are competitive entities. LMP values are calculated and posted every five minutes, one step lagged. They send an ex ante dispatch instruction, calculate an ex post price consistent with the earlier dispatch instruction. These are integrated in the full network model transmission system, they recognize the physical realities of the power grid operations. Pricing and tightly integrating the real time market with actual operation makes the market work. This has created a decent success story within PJM for short term operations.

There are other markets in PJM. The day ahead market is a full transmission model, based on the same security constrained dispatch except there is a unit commitment because of forward scheduling. It is quasi physical and financial. It lives in both worlds. It is physical in the sense that it respects security constraints, it allows generator units to bid their physical parameters and honors them in the unit commitment scheduling. It's financial though because one can put in financial bids not tied to any specific physical asset or demand. There is also a trading hub that is a virtual pricing point. People can bid to sell and buy energy there on a digital basis. What makes it work is that the calculation of clearing prices is consistent with the real time model and the full transmission network.

Then there is the financial transmission right auctions run annually and monthly. They are also consistent with the physical realities of the system; it is all internally consistent. This eliminates artificial arbitrage, or gaming. When people take a position in the day ahead or the FTR market they have confidence the position will be honored. The consistency is important to avoid perverse incentives. PJM considered splitting the markets previously but they cannot; it's one of their fundamental successes.

The integration of pricing and operating conditions have made market participants real partners in running the power grid. PJM gives them the real time transparent spot price, they react to it and ensure reliability. It works implicitly, it works very quickly. Before they implemented LMP, it took PJM around 30 minutes to control a transmission constraint, now it takes 3-6 minutes. This is a ten time increase in speed to control and maintain reliability in the system.

It's also important that PJM made the real time and day ahead market internally consistent and operated flawlessly. If they do that, the financial products should develop themselves, especially with a robust spot market. A big part of this was to create standard product definitions like "trading house." Creating clear candidate definitions of the western hub in PJM or the AP Dayton hub and northern Illinois hub was important so forward markets could catch on to those hubs and develop trading around them. They felt it was their responsibility to kick start forward liquidity to trade, but not to go further than that.

Another goal was to create unprecedented information transparency. Give market participants more information than they ever thought they needed about how the market's operating so they could rationalize the prices. This is important because it allows them to test the accuracy of the prices and instill confidence. They created a large e-data system posted to their area control so people can watch the supply demand balance. It includes transmission flows and limits, and other aspects of the operating system.

A recent change at PJM has occurred in their FTR market. In the past it ran on an annual basis and there were no reconfigurations on a monthly basis. If you had bought a year, you could reconfigure August in July but you couldn't reconfigure the rest of the year because there was no auction that extended for the balance of the year. They recently implemented a more sophisticated monthly auction to allow people to buy more products, and to allow for reconfiguration. Some asked whether PJM should be doing this, and spending the money on it. There was a huge amount of interest and big increases in the megawatts so clearly it was a worthwhile change and expenditure. They almost didn't implement it.

Let's look at some of the problems within PJM. One problem is that the forward products are not terribly far forward. There isn't trading much longer out than about 18 months. This lack of forward trading is a cause for concern. There is an observed lack of forward trading volume and that should be addressed.

The general complaint is there's a lack of reasonable forward hedging product availability. This complaint comes from the industrials, the muni and co-op communities, etc. They say nobody will write me a long term contract. However, the generators say no one will buy a long term contract. It could be the bid spread is too large but it's hard to say – neither side really seems to be talking to each other.

Market participants complain they cannot trade on ICE, don't want the standard 50 megawatt block contract; they want 32 megawatts or eight megawatts. The standard products don't work for them. Gas markets have developed extensively this way but not electricity, perhaps because there's no storage, etc. However, high volume in gas occurs because the smaller players can participate in the forward market. In electricity there are no varied products for the smaller players. Demand responders can't deal with block contracts. They need a special contract. Steel companies who have a 40 megawatt load don't want to buy 50.

Participants complain they must purchase forward energy and transmission separately. They can't take a position to cover energy and transportation in one shot. This is a bigger concern for smaller stakeholders, the large ones can put it together just fine.

Credit issues are a concern because PJM imposes difficult credit requirements. The small players can't manage the credit requirements.

Finally, the wholesale retail market interface is not functioning well. This may not be PJM's job but it's something that has not worked. The question of regulating the retail market in a competitive wholesale market environment is not clear at all.

How can PJM address some of the problems? First, should PJM calibrate its settlements to reduce some of the credit requirements? Should they try to find somebody to do a clearinghouse function? Obviously they can't do it themselves, it requires a lot of money but should they foster clearinghouse type mechanism? Should they be fostering more flexible forwards? Should they worry about the split FTR and energy exchanges? These are the questions that PJM is facing in the near future and which we can discuss today.

Question: How long is their FTR auction for? What's the length of the contract?

Speaker 1: The auction still goes out one year but the reconfiguration auction, the monthly one, is extended now. Instead of offering just one month at a time, it allows you to reconfigure products through the rest of the year. The monthly auction changed from just a single month auction to a balance of year auction including months. One can purchase multiple months in strips.

Question: Is the fact that people can't go longer than a year with FTRs an issue?

Speaker 1: Yes. It's being debated now in the stakeholder process, should they have a three year auction? I think it should be at least three years out.

Question: You said PJM absolutely cannot split the markets from the operations?

Speaker 1: Yes, the evidence shows that fundamental consistency between the LMP and the grid operations is essential. If you split them then it wouldn't make sense financially because there would be repeated functions.

Question: I'm always surprised to hear industrial customers can't get access to long term contracts. I know companies willing to sell them. Has PJM independently looked to see what the situation really is?

Speaker 1: Well, clearly some of the data I've shown demonstrates they aren't occurring.

Question: It shows they don't exist but it doesn't show that they're not available.

Speaker 1: They don't exist on the exchanges. The anecdotal evidence from individual stakeholders is systematic but it doesn't hold together completely because there's a gap between both sides. There's no clear evidence.

Question: In the various solutions you discussed, should PJM have a role in these? Could PJM have a role?

Speaker 1: Yes, they could. The question is should they have a role? They couldn't have a role in a clearinghouse other than to act as a conduit of information. Otherwise a large financial institution is needed. They could have a role in fostering it though.

Speaker 2.

I will focus on what the market monitor is looking at and then try to bring it back to the larger issues of the session. I'll focus in part on the ERCOT market in Texas.

Competitive markets because they can organize these complex processes. Electricity is particularly unique and complicated; it requires a level of coordination that isn't present in other competitive markets, even others that are capital intensive. In electricity we want economic dispatch over a broad area, productive efficiencies, and good price signals for generation and the demand side to spur investment and consumption decisions. These are the goals. A market monitor is seeking to ensure these goals are being met.

The market monitor asks a variety of questions. Is the market providing incentives to suppliers and loads? There's substantial evidence that real time and day ahead market structures work in the nodal LMP markets. However ERCOT in Texas is zonal, not LMP. It's like a 4 or 5 node LMP market. It works, the lights are on, and the demand is about 39,000 megawatts. It's got some warts, though, and so ERCOT is transitioning to a nodal market structure over the next couple of years.

Second, is the operation of the market undermining the efficiency of the market results? This can be due to market participants behavior or also the system operator. If the modeling procedures and rules are designed improperly this can happen.

Finally, are participants able to abuse market power? It's a difficult but important question that needs to be answered. They want to ensure that the ability doesn't exist, or if it does then it is not being exercised.

This is done in large part through real time screens. Periodic reporting and analysis of real time data shows trends that can be detected. Then that information is backed up with explanation to provide answers to various folks; the public, policy makers, politicians. The monitor should be able to tell them if the market is producing competitive outcomes and why.

The focus is on market rules that may create efficiencies, gaming opportunities, and potential market power abuses. Most people assume a market monitor is a cop looking for people breaking the rules. While true, it's not the majority of the time that's spent. Hopefully there's a certain deterrent effect similar to a traffic camera at the red light of an intersection. There is so much work to be done on the market rules side as well.

The primary delegated authority for a monitor is investigative. They have the authority to access and analyze all the data in the market. They can also request additional data from market participants as deemed necessary. They must protect the confidentiality of that information. Enforcement authority is often retained by the regulatory authority. There's a division between the monitoring and investigation, and then the enforcement actions. Maintaining the credibility of pricing outcomes in the market is critical. Market monitors and system operators shouldn't have the ability to change prices or rules on an ad hoc basis. Only in the case of system and software errors.

In ERCOT the market is analyzed on an engineering basis at a nodal level but on a commercial basis it's viewed at a zonal level. This creates inconsistencies in the physical reality of the system that really should be kept consistent. Those are being changed. The style of the market doesn't change the scope of the market monitoring that much. Nodal markets tend to be more transparent and easier to monitor. In a non-nodal system, distinguishing between activities like withholding versus inefficiencies that are just attributable to the market design is difficult. A nodal market makes that job more straightforward.

There are some market performance improvement areas that are not necessarily market power abuse. Modeling procedures, system operations, and pricing rules that can lead to inefficient prices and outcomes. These should be part of the principle roles of the ISO. Some engineers at ERCOT think that you can't change this in part because of NERC standards. Their tendency is to be focused on the reliability aspects and not on the damage to efficient outcomes.

For example, in ERCOT there is an abundance of wind generation, over 2,500 megawatts and double that very soon. Reliability is difficult because wind is intermittent. It's like you're preserving a lane of the highway in case one lane gets blocked up at all times. We need to change the mindset a little bit. There's so much of it without any incremental investment. Through change in procedures you could really free up a lot of capacity at zero cost almost. The challenge is to improve the efficiency and maintain the reliability.

Inefficient conduct is another area. Often this is rules that motivate market participants to behave inconsistently with competitive expectations. There's strategic conduct, or flaws in market rules, that create opportunities. Sometimes it's challenging to differentiate between inefficient or strategic conduct. It's critical to do that because it determines whether one remedies a market flaw, or tries to address an itinerant market participant.

Mitigating market power depends on the principle role of the RTO. The best form of mitigation is to address the structural characteristics of the market. Most people would agree with that. Promoting transmission investments reduces congestion and associated locational market power. You get two benefits from that approach.

The ISO should play a leading, coordinating role in this. It's a difficult process because they have to plan transmission and they don't know what generation is going to be there. Nonetheless, ERCOT spent over $1 billion for the last five or six years, it may be even twice that. The cost to the residential consumer is low when you figure it out. Over the last five years it's been a $1 per month increase. That's relative to the $2-5 we heard on those auctions earlier. There's a lot of value in adding transmission. Long term FTRs manage congestion risk that can be mitigated if there is a good transmission planning process in place.

Removing barriers to investment in new generation reduces market power. There is a robust coordinated generation interconnection process in ERCOT. It formed the basis for some of the FERC work when Pat Wood was there. Facilitating demand side participation in the market is important as well. The RTO should play a leading role in all three of those. Divestiture is another structural remedy but the ISO should not be involved in that, obviously.

Scarcity pricing and efficiency have been a real problem. Getting the right prices at the right times regarding scarcity has not occurred. Scarcity pricing plays a critical role for allowing the existing marginal high cost units to stay on the system or to leave the system. It provides the economic signal to motivate demand response and attract new investment. Markets have to be designed to allow for scarcity pricing so that prices rise sharply during legitimate shortage conditions. They're raising offer caps in Texas progressively to $3,000 per megawatt hour. A long term solution is to utilize a demand curve for reserves at high levels during legitimate shortage conditions.

There is a lot of opportunity for enhancements with demand response and the RTO. Setting efficient market prices during peak conditions, improving the efficiency of the consumption decision, increasing reliability by rationing scarce supply for loads that can move off peak during scarce conditions, and mitigating market power by limiting price increases. RTOs should understand and embrace their facilitator role for the energy, ancillary service markets and capacity markets as well if necessary. The true value of demand resources needs to be reflected in the pricing so distorted outcomes that spread out prices over times where the value is not there don't occur.

ERCOT is a wholesale reliability coordinator. They're a centralized switching agent and a settlement and registration agent for the retail market. They receive six million meter reads from retail customers. They do wholesale settlement for the whole market. For most of the customers you have one meter read per month. ERCOT can tell you how much you consumed every 15 minutes through a load profile. Of course it's not real because customers don't have interval meters. That's a problem in demand response. For instance, air conditioner cycling programs are important in Texas. A provider can cycle customers on an air conditioner program and apply a profile that puts all the energy in buckets that aren't in the right time. ERCOT needs statistically based profiles that can be dynamic and reflect these kind of programs to facilitate additional demand response. In Texas, a program like this has a lot of potential.

Speaker 3.

Two months ago I heard about this project of PJM's Board of Directors to rethink strategically and re-examine what they should be doing, what are the gaps, and what the future directions for the development of the RTO should be. Then I saw documents that posed a series of more specific questions and I was terrified [Laughter]. I was concerned about two things.

First, PJM is the poster child for how to do this right. Now PJM doesn't have everything solved of course. There's a lot of problems but basically we're talking about fixing things around the edges. The basic core structure of it is exactly right. New York, New England, new directions in Texas and California, all show movement in the same direction. Anytime PJM says anything about its mission it will reverberate everywhere in Europe and down in New Zealand and every place else because they're watching what's going on here. A year ago, the libertarian Cato Institute said we need to regulate this whole system completely because the experiment in using markets had failed. When a libertarian think tank says this it's fundamentally troubling. So if PJM got up and said it's broken, that would have very broad implications.

Second, I was concerned because some of the questions in the document implied that problems with the market design in California occurred because they were badly implemented but if they were implemented well in the mid-Atlantic states they would work fine. However, critical features in the California market design – the separation of the system operator and the California PX – could never work for fundamental reasons. The question addressed the possibility of a narrowly defined RTO separated from the market operators. I was very nervous about this idea.

My emphasis today is the relentless repetition of why the separation fallacy of the ISO and the market is a fundamental mistake. Don't do it, it's a fallacy, it's a mistake, you can't do it, it doesn't work.

Certainly, rethinking what we're doing with RTOs is a valid thing to do. Assessing the experience and learning from it. The RTOs are critical. A flaw in the Cato argument was the assumption that RTOs were not necessary. There has to be a regulated monopoly; no regulation at all is impossible. There can't be complete freedom of action. RTOs implement critical things necessary to support markets under open access and non discrimination.

A necessary functions for energy markets is the core element of real time bid based security constrained economic dispatch with locational prices. It's critical, the only way to meet the twin objectives of open access and non discrimination. FERC's review of order 888 needs to understand this if they are going to address the open access and non discrimination values seriously.

Effective long term hedges are another necessary function. Arguably you can run a real time market without long term hedges like they do in New Zealand. If you want long term hedges then financial transmission rights are necessary. This involves the core function of connecting to real time dispatch, a clearing mechanism, and processing locational differences. Generally, it has to be done by the RTO. Long term hedges are not necessary but they're highly desirable. However, they do impose certain constraints on what the day ahead market can look like to make it consistent with the real time and the FTRs. Transmission planning and investment protocols also have to be integrated. It's not absolutely necessary that the RTO do this but it's highly desirable.

For everything else, whether the RTO should do it is arguable. Some other company could do it. People can have different views about this. Ancillary services and resource adequacy are both examples of functions that the RTO might do, but doesn't have to. They do have to be done in ways that are consistent with everything else. We do have to keep thinking about how these things fit together. I'm concerned that current hearings at FERC are parallel stovepipe conversations: one about security constrained economic dispatch, another about transmission investment, another about order 888, etc. We cannot address them separately, they interact. You have to think about how the pieces fit together.

Consider ancillary services for frequency, AGC, or automatic control. It's probably too hard to figure out exactly how to implement because it can't discriminate. In this case you have to spread it across everybody and uplift. Here the RTO has to determine if it gets used or not, they can't allow people to choose whether they're participating in that. When we consider the actual generation from the plants, the whole point is to allow people to choose. Here the pricing must be consistent and that consistency has to be throughout the whole system.

Earlier, we discussed reliability people at the system operator versus the markets people. For instance, in New York with the NERC standard 2.8 and reliability rules there's some confusion. Some view it as discretionary and others argue it's not. However, a secondary and important issue is that if it is being used then the prices for the ex post dispatch must reflect that rule.

So if the standard says you have so much excess capacity on the system then the prices should reflect it. We don't want a perverse situation where the prices go in the wrong direction. That's a big problem. System operators need to adjust the prices to reflect these kinds of standards.

Reform is not going well, order 888 review has now got us in an infinite loop. Somehow we're managing to revive the separation fallacy and that is wrong. All these short term operations must be kept together, they are critically inter-related.

An important issue is scarcity pricing and the operating reserve demand curve. In a lot of the RTOs there's a rule of thumb that is conceptually right most of the time except when it really matters. The rule is that the variable operating cost of the last unit running should be the market clearing price. That's true as long as they're not near capacity but when they hit capacity now you're supposed to be somehow on the demand side. Originally people said demand bidding will take care of that but that never happened. They've got this rule that's wrong just when they need it.

A critical detail to address this issue is an operating reserve demand curve to serve as a proxy for this scarcity problem. This mitigates exorbitant prices when they're out of capacity but still allows them to get very high and solves the missing money problem. It makes forward capacity markets easier too. They should be implementing it everywhere but they're distracted. When that system is implemented and the prices are right and consistent with the rules there are extensive virtuous circle effects.

Transmission investment is the second major issue. I advocate the Argentine approach. It answers several questions explicitly raised in recent FERC orders about PJM. How does the RTO or central planner make a decision for economic investment or leave it to the market to do it. In the U.S. this model would address major expansions of transmission by "public contest" method. This overcomes market failure without overturning markets.

The regulator applies a standard "golden rule" cost benefit test. The same test is used to identify expected beneficiaries. The 30%/30% rule is applied: 30% of beneficiaries must be proponents and no more than 30% of beneficiaries can be opponents. This provides an alternative to a "market failure test" to help the regulators limit intervention and support the broader market. Costs are assigned to beneficiaries with mandatory participant funding. Finally, auction revenue rights or long term FTRs to beneficiaries can be allocated to them as well. This model ensures that the whole process doesn't unravel, a major problem in current U.S. RTOs.

Where are we now? Currently FERC's order 888 NOPR review is taking us nowhere. Chairman Kelliher of FERC said the following in the process of looking at open access and non discrimination rules: "We are not talking about market design, we are not talking about restructuring, we are talking about preventing undue discrimination and preference." There's two possible interpretations for this.
One is that he doesn't mean what he says, which I find quite disturbing. The other possible explanation is he does mean what he says, which I find quite disturbing. [Laughter] Rules for open access and non-discrimination are intimately connected to the market design questions. We've gone over this here today, and it's been addressed time and again in the past. Open access implicitly involves market design. The fact that the denial has risen this high at the Federal Energy Regulatory Commission is very worrisome.

Speaker 4.

We should commend the RTOs and ISOs for the performance to date. Nothing in these systems is really broken and they have handled a lot of stresses in the system; peak loads, new generation, new capacity, and bankruptcies of some of the leading energy companies. What we see in markets like PJM is something that clearly works. Looking forward however, a key concern is the level of investment. There is a concern that investment is being curbed because of the inability to secure a long term price at sufficiently high prices. I'll look at some of these issues and also discuss new products that could be encouraged by the RTOs to make the market more robust.

On one hand, other industries like Intel or Boeing or even slow growth industries like paper companies do that without long term PPAs. However, they don't have the same threats of price caps and regulatory instability. The markets could help address that – it's important for traditional investments as well as renewable investments. Demand response is an important issue as well that's been discussed somewhat. The ISOs and the RTOs perform two functions. Reliability for the grid, and the operations of the markets. Their objectives are fair competition, efficiency, investment.

Pricing problems show up in a variety of places. The markets are not reflecting long term markets and long term energy prices. There are gaps terms of products. There are concerns for price caps. Some are explicit with absolute ceilings, some are inherent in terms of which plants are dispatched out of merit and others that are not. These soften the pricing signals to the market for investment or demand response. Consequently we get potential political solutions or mandates instead. Mandated renewables or demand response are some examples. These are all market limitations.

Is a more robust market, populated with more competitors and offerings, possible? In markets such as natural gas or corn they have a ratio of something like 40 to 1 of financial trading versus actual physical sales. In current power markets my data shows it's more like 6 to 1. Clearly there is an anomaly. There is a potential to see more trading and volume with the electricity markets. Some characteristics in electricity markets should motivate greater trading, such as increased volatility. It's 2 or 3 times that of natural gas. This occurs in part because power can't be stored; there's no inventory to smooth underlying production costs. Bilateral markets can be expanded as well. They already fulfill some trading needs but they could do more, especially in a publicly cleared exchange. An exchange provides price transparency, easier terms of credit because you can offset positions, and aggregation of supply and demand at a single point. Buyers want to go to the exchange with the most sellers and sellers to the point with the most buyers.

Thresholds are necessary for that kind of exchange. When we compare electricity to other markets it takes a center role. With corn, oil, or natural gas exchanges clear products are available and there are many suppliers and buyers. Electricity has had rapidly increasing participants but huge physical volume is also needed. Further, volatility increases the need for diverse products. Finally a commodity product is needed. For all these reasons an exchange would be useful. A more developed exchange would increase the number of participants, create more transparent commitments and transactions, and enhance stability.

An earlier speaker discussed a what is in essence a recent test case at PJM. Their market was expanded to include balance of period trading for the FTRs which were previously only available on a monthly and annual auction. And the volumes in response instantly doubled. Bilateral trading increased substantially as well. There's good evidence that if you build they will come.

There are three dimensions for potential products in the market. One is the energy versus spread products, the other is time, and a third is location. In PJM there is a market with well developed exchanges at the hub which settles PJM west against PJM's real time market. However many of these markets don't incorporate time, i.e. longer-term contracts. Curiously another gap is the combination of spreads and energy. One would think this would be a natural product in the market where a generator could sell power at the point where it's produced and a consumer can buy it where it's being consumed. The components are there but the integrated product is not. An analogy would be if you want to buy a car but you have to buy your tires from Goodrich, a transmission frame GM, go to Caterpillar to buy the engine, etc. To complicate that you could only buy enough gas to last you for one day. It's complex for smaller participants to deal with.

Having the whole product available, and having it available in the sizes people are looking for would improve things greatly. Not just 50 megawatt chunks but in various volumes as well as time frames. This could fuel a lot of liquidity that doesn't currently exist. These kinds of products would enable the participation of smaller participants which creates more involvement, better equity, and further efficiency in the market.

The challenges for these products cannot be addressed by the typical exchange. Typical hub products like ICE or NYMEX are one to one exchanges that exist in having a buyer, seller, the same product, the same location, the same price. An adequate number of participants in the market is all you need. LMP exchanges in the PJM system would need to settle across 9,000 nodes. It's hard to imagine enough buyers and sellers at each node to settle on a price. Instead there is a more complex exchange that allows multiple sellers to function with products and locations that are different; and it's inherently what has been described earlier in terms of the security constrained bid based economically optimized process, a market model. This model is critical for these new kinds of products. If we talk about the hedgehog and the fox, I'm not sure which is the hedgehog or the fox. One would consider the classic hub exchanges as the more dynamic but the LMP exchange is by far a more complex structure to implement.

There are some concerns in the governance of PJM that inhibit market development. For instance, an earlier speaker described how the balance of period FTR auctions almost didn't happen. Further, staffing and budgeting is strained and shared across a lot of different priorities. There is a legitimate question of whose money should be paying for market development. Many participants are interested in reliability but aren't concerned with market development. The governance within PJM is focused on reliability; many participants serve load and participate in many sectors; those issues take a strong priority. Financial participants aren't as involved. They should be more involved but clearly they're in the minority. There are incentives for talented staff to develop these kinds of markets. There are considerable differences in talent compensation between other exchanges and PJM. There are regulatory jurisdiction issues – is it FERC or commodities regulation, or none at all in the case of ICE with OTC cleared products. Finally, mistakes are part of the market world but they are less acceptable in a regulated world.

These issues can be overcome. My immediate wish list would include additional products like the FTRs within PJM, and determining who should provide such products.

Question: A lot of the products we're talking about are standardized forward contracts on exchanges as opposed to over the counter bilateral long term arrangements. Some companies are doing long term arrangements. How much of that goes on, or could go on, and how is it different than the standardized exchange data.

Response: Long term contracts are available but there is not agreement on price. Many buyers want contracts that are not tied to fuel prices or that are extremely low. There's a disconnect.

Speaker: Recently an executive was in a meeting with folks in the governor's office and hearing that large industrials in western Pennsylvania were not getting long term proposals and yet he specifically had a long term proposal in front of two of them. They just didn't like the price.

Question: In the Argentine model there's reference to beneficiaries that are identified in some manner. PJM has been struggling with this question and no one is satisfied.

Speaker 3: It's an economic evaluation of the cost of benefits. It involves 15 year simulations of the system with and without transmission investment. They have to make assumptions about prices and what gets built. There's some uncertainty but you have an estimate of benefits and also who receives the benefits.

The innovation in the Argentinean system is they do the calculation beforehand and allocate the costs and benefits. The beneficiaries get voting rights in proportion to their estimated benefits and they get cost allocations in proportion to their estimated benefits, then they get to vote. More than 30% of the beneficiaries have to vote against it to stop it. It addresses the free rider coalition problem. If they don't get 30% opposed then it goes forward, and the costs are allocated as already defined. If more than 30% vote against it then it's not a good idea to go forward in any case – there's clearly too much of a disconnect. The people who are supposed to benefit and are also sharing the costs don't want it. It does address the free rider and large lumpiness sort of problem.

Question: Are the votes weighted?

Speaker 3: Weighted by the benefits, exactly.

Question: Can I ask two clarifying questions to your answer? However PJM or the RTO conducts the cost benefit analysis, for example if they use a production cost method, that's how they should assign the beneficiaries?

Speaker 3: Yes, it should be consistent.

Question: Does it make a difference that in many regions, like PJM, there are not customer specific allocations? They allocate costs based upon a zone. Within a zone you may have many customers that benefit and many that don't, even using PJM's analysis. And some customers have operations in multiple zones. How would that work?

Speaker 3: This is a second best solution. It's not going to be a perfect allocation. And I'm a nodal guy so zonal things always worry me. It needs to be enough of a degree of disaggregation to achieve a rough justice. It would help to use nodal differentiations if you had representatives who could do the voting, and that would be fine.

Speaker: The zones are used more for transmission rate design issues. If you did something like this obviously you could group the beneficiaries differently because of the weighted voting rights and it would be charged out differently than the standard transmission rates.

Question: Do they allocate the cost of these new transmission upgrades to someone other than load? To generators?

Speaker 3: Yes.

Speaker 2: It seems that ascertaining nodal level cost and benefits is unreliable. In ERCOT the postage stamp pricing is in place so all loads pay for transmission regardless of where it's built and which transmission company builds it. It's paid on a coincident peak rate basis. Small companies could hit for this. A company I worked for previously paid up to about $10 million a year, and that's every year, for payments relative to their transmission cost of service. Many people in Texas are still upset about this and this was implemented ten years ago. However, the same company that paid 10 million per year gained at least 250 million in benefits as a result of greater buyer and seller access in the wholesale market. It's not participant funding, there's no merchant funding, but there's a huge amount of investment in transmission in ERCOT because of this pricing mechanism. It's easier there of course because there's only one regulatory jurisdiction and there are no multi-state issues.

Speaker 3: For transmission investments, it's inconsistent to say we can calculate the benefits and but not the locational beneficiaries. The whole point of transmission is the locational effects and how it changes the dispatch. They can make a calculation that shows benefit relative to its cost and an approximation the beneficiaries and the scale of benefits that they get. If it's uncertain who the beneficiaries are, then the benefit overall is uncertain.

The Argentine example is real. It's quite successful but because it's all done in Spanish no one knows about it. They've done a lot of transmission investment this way. There is one big project they didn't build and they kept voting against it. It didn't satisfy the cost benefit test. It wasn't a good idea to do it.

Question: In terms of FERC and the 888 NOPR reform, FERC cannot implement SMD in states without RTOs. Is their inability to do that mean there's nothing they can do to improve open access?

Speaker 3: SMD was an elaborate, comprehensive proposal with good and bad aspects. They chucked the baby with the bathwater. It is impossible to have open access and non-discriminatory pricing without real time security constrained economic dispatch. You're going to have discrimination.

FTRs are not necessarily mandatory. New Zealand has none. Day ahead markets are similar; PJM ran for just fine without them. Resource adequacy programs can be optional. Merging control areas. All optional. The one thing necessary is bid based security constrained economic dispatch for real time and locational prices.

Question: I detect a contradiction. The period for contracts in the marketplace appears to be contracting, but there's concern about generation investment which normally ought to expand contract time lengths. Buyers would become concerned about short periods and bid up the periods in order to get more generation. The underlying conclusion is the market isn't working or that market players are behaving irrationally and not able to see what's happening, but everybody here can see what's happening. What's going on here?

Speaker: There is irrational behavior by market participants on a long term basis because they know prices could go up. This is driven by a lack of clarity on who will have responsibility to serve the load. In some jurisdictions with short term POLR service obligation auctions there's nobody saying I need to take care of that load for a period.

That's not a problem in a muni co-op situation. They have rather sparse forward participation. They may be waiting for prices to rise. They may not believe the forward price because the exchanges are incomplete. If additional exchange markets are implemented that may increase trading and confidence in these kinds of deals.

Speaker 2: I can speak for the perspective of a large muni, about 4,400 megawatts of peak demand. They were typically long in the market although the market became oversupplied for a while. They became a net buyer for quite a while, it just made sense. The exchange data may not be telling the whole story. In the last 3 years ERCOT has gone from being oversupplied with mothballs and retirements to planning reserve margins in the 15% range or less next summer. A recent RFP for more than 100 megawatts came out recently and responses were favorable. People are looking to buy power.

Speaker 4: People disagree as to what a fair price is. There are not enough transactions for folks to settle in with confidence. They are keeping contracts small if they do them, doing it with little pieces first. It's easier to cultivate a long term market by stepping into it gradually rather than in big chunks over a long time horizon. That's why smaller contract transactions would be helpful, and an exchange to provide transparency. That's how to grow confidence. There have been strong volumes, it's not a stagnant market. Volumes traded on the ICE hub have grown quite a bit recently.

Speaker 3: I would make four points, two go one way and two the other. First, standardized exchanges are not all of the long term arrangements. They are public but the over the counter market and long term things, we don't have that data. So there's more of this going on out there than we know. Second, finance and deals are changing. Developers no longer need a ten or 15 year contract in order to develop generation, they need a three year contract with creative bank financing and gas hedges to get it rolling forward. These issues show that it's not so bad.

However it goes the other way too. In the organized RTO markets it takes six hours a year at $10,000 to justify the cost of a peaker. If the price is capped at $1,000 why should you build a peaker? That impacts long term things. That's why this operating reserve demand curve is important. Second, particularly in places with retail access, the obligation to serve is no longer. So for the residential customers, there's nobody with an obligation to buy for them long term. That dries up long term demand for contracts and reduces the volume for long term contracts. Customers don't see it because they're all default. They used to have ten year hedge and now they've only got a rolling three year hedge.

Question: The questionnaire that PJM put out for it's strategic review was upsetting because it raised issues that have been decided and proven long ago such as Bill's separation fallacy or other structural questions. It's important to re-assess mission and strategy but these were inappropriate questions. Were there other motives in them? A balm for whiners and criers who have never given up on these issues. Why the backward questions in a forward looking exercise?

Speaker 1: There is a significant portion of our industry that are questioning the benefits of wholesale markets and LMP. I hear them all the time. One can ignore them or create an initiative that analyzes and reaffirms why they're wrong. PJM went and put it together in one package and answered the obvious question.

The scope may have been broad but the process of convincing people requires that the obvious questions be analyzed and re-analyzed. PJM put another study out that looked at the benefits for muni co-op rates inside markets and outside markets. There have been six or seven studies in the past, but they keep on doing them.

Question: The FTR auction changes have been effective and successful but also barely got passed. Is the decision process the right one? Should it be more of a political stakeholder process; quasi initiative or referendum. Or, should it be quasi-regulatory, doing the right thing through the correct decision making. What's the right RTO governance going forward?

Speaker 2: The big concern in these issues is for participants who have to pay for it but aren't going to use it. They may be concerned that the RTOs resources should be getting use for other things.

Speaker: In the balance of time period FTR issue, a large group of load interests were very concerned about it.

Speaker 1: One way to handle the governance has to do with cost allocation. How does the RTO actually finance a project then? There has been considerable discussion in PJM about fair representation within the stakeholder governance body. They have one large sector stakeholder group that is 150 companies and others that are much smaller; sector representation may be out of line. It might be better to consider how much money people have at stake in the market as a voting allocation. They need to review this issue certainly.

Speaker 4: There's no silver bullet for governance. It takes a long time to get actions resolved because the membership is so diverse and has different priorities. The appeal of this Argentine model is that the beneficiaries are the ones voting on it instead of the other interests that aren't affected. Sector representation can certainly be improved – it's based on a system done some time ago and the landscape has changed dramatically. There are a lot of diverse interests that warrant being broken out as their own sectors.

A third improvement would be more involvement by senior level executives so that resolution of tradeoffs can occur more quickly. The lack of decision-makers in negotiations slows things down.

Segmented budgets could help also. Scarce resources, talent, money could be segmented to make progress on different fronts. If PJM had a segmented budget for market development, it wouldn't be as much of an issue.

Finally, the balance of period FTR market paid for itself in six months. It's generating cash on an incremental basis is my rough analysis.

Speaker 1: Generates cash?

Speaker 4: If you look at the fee associated with the bids.

Speaker 1: It's possible those fees could reduce rates in the future.

Question: Utility commissions hear complaints that ISOs are spending too much money. My guess is they're spending too much money in some areas but not enough in others. For instance the cost benefits for software developments can provide huge discounts and there could be more progress and spending there. Further, the commissions are often asked to do cost-benefit analysis for projects in the ISOs. It's hard to judge whether or not PJM should put in another forward market or concentrate on getting better ancillary service co-optimization in their day ahead market.

I'm not sure if an ISO should be trying to reach the goal of 40 to 1 ratios in financial to physical trades like natural gas. Perhaps an RTO should be happy with their 6 to 1 ratio. Perhaps commissions should be pushing for better integrated real time bid based security constrained dispatch. It's very hard to make ex ante judgments.

Speaker 4: A 40 to 1 ratio shouldn't be a goal. It simply indicates that additional liquidity is possible. The more liquidity then the more efficient the pricing. The more bids and asks on a commodity the better prices will be.

Question: OK, but how does a commission evaluate whether PJM should spend more time on joint dispatch or changing their day ahead unit commitment model? How can we quantify the benefits?

Speaker 4: Maybe the answer is both.

Question: Yes, but then you have to convince a commission that the budgets have to get larger. PJM has to justify their budgets and that's an issue under a lot of pressure.

Speaker 4: It's a little of the fox hedgehog syndrome. Do you expand with more products like the fox or do you focus on the core hedgehog duties.

Speaker 1: This is the conundrum. Personally I believe that PJM should develop a financial forward market that goes out a year. It would be used by these players who want to dump their FTR and energy position together. One way to do that would be just get somebody to fund it, build it and then charge fees and recover the cost. Should PJM be in that role? Whose responsibility is it to get it done? Many of these initiative will be positive, but how to get it done is the concern.

Question: The further you go out, the more uncertainty you create. PJM probably shouldn't take the uncertainty risks in longer forward markets, should it? What happens if the RTO gets it wrong? If they get it wrong in the FTR market, they make it up with some pro rata allocation rules. If it's a ten year market do they just fix it with pro rata rules?

Speaker: Ideally, PJM, or whoever has the exchange, as well as parties and counter parties would handle the risk.

Question: PJM is in a different position than ICE or NYMEX. They put their own risk capital on the table. PJM is putting somebody else's capital there.

Speaker: Right.

Speaker 1: If PJM ran such a market, the funding for the transportation is based on the capability of the transmission system. If another entity ran it, they couldn't use that. Everything would have to book out and be neutral, or they would have to take on counter party risk themselves. PJM cannot take on the counter party risk as it sits today.

Question: The key issue of long term liquidity in matching up a buyer and a seller around some bilateral deal, reflects who's going to take care of risk. Who holds the long term risk on the transmission side between the location of injection withdrawal. One proposal is to have effective long term hedges as a necessary function of the energy markets and provide a forum for these FTRs. Does the ISO have a function here? Is there a necessary function for the ISO in this long term hedge? Should that be a market? How does it square with this allocation requirement of long term rights being debated currently?

Speaker 3: If you want to have long term FTRs that settle against day ahead prices and can be reconfigured over time then the RTO must be involved to address the dispatch problem. It can't be avoided. There is a risk associated with it to some degree. It's neither trivial nor extensive, the risks don't grow at the same order of magnitude as if you were talking about being long or short in energy contracts. That's a different matter because they might have oversold the grid and then something happens. For instance, they ran the auction for a year and then the Delmarva line was taken out of service. That's a problem. However, these issues are not prohibitive or debilitating. Generally, I think these markets can be extended. The risk of being a little short or a little over is surmountable but the RTO has to be involved.

There are other problems with long term FTRs. The people who build and paid for an expansion are going to be forced to sell them under mandate. They're going to have to sell them cheap because nobody's going to be willing to pay much for them, there isn't much demand. That's a different kind of problem. But I don't think dealing with

It's another matter to have the RTO set up many to many, long term multi party exchanges; these are energy bids. The energy price exposure if you're long in an FTR and the price of electricity doubles nothing much happens. The relative differentials will be about the same. When the energy price doubles and you're long on energy that's a different matter.

Question: Is there a way to make these things more closely linked? If the RTO is going to be the primary purveyor of liquidity for locational or transmission hedges but not for other things how do can energy and FTR products be more synchronized? How does this play out for the ISO?

Speaker 4: I will add a question. I hear a lot about pairing energy and transmission together and there's capacity markets too. Is this something to consider also?

Speaker: There's a tie between energy and the FTR but the capacity is more like a special type of call on energy during an emergency.

Speaker 4: But there's an obligation on load serving entities?

Speaker: Or on the generator, yes. The risk they take is quantified separately to say when they sell forward energy contracts they must acknowledge that the energy may be spoken for from the capacity resource. They have to reflect it in whatever they offer in energy. There's no necessity to have the market for capacity integrated with energy supply because you can index it.

Speaker 3: Another feature of long term FTRs is worth considering. In order to define long term FTRs, you only have to use the existing grid.

There are no assumptions about the expansion of the grid, future investments, or fuel prices. They are simply derived from the existing grid. A long term energy hedge for ten years that's locationally derived, with multiple parties and incorporates growing demand and changes in energy prices is much more complicated.

Question: Is load taking a risk or supply? In areas like California where there's the prospect of retail access it's difficult for load to take that risk. On the supply side, generators and the banks seem unwilling to take it. I haven't seen developers being able to finance a three year PPA. If this is just beginning to happen, that will be great. On the bank side they are concerned about changes in the regulatory framework over the space of that generation commitment.

California is using a model similar to Argentina: identifying infrastructure that's needed and an allocation framework with beneficiaries paying. Their PUC has approved its use for utilities and new generation. It's similar to the proposal in PJM for 15 year backstop contracts. If they see new generation is needed and the market is not working then the 15 year backstop gets allocated out to users. This seems similar to the Argentina proposal. Was there a suggestion that it could be extended to generation as well? This definitely creates a role for the RTO, determining the need and becoming the vehicle for the process. This is probably a better long term solution than the transitional solution in California. Do I understand the application properly?

Speaker 3: The Argentinean experience and its application to the US context does not deal with generation or demand side investments. In those situations beneficiaries are obvious, and they pay for it. The large scale transmission investments have a lot of free rider problems.

Speaker 1: The PJM backstop is under the capacity market model and involves a series of performance assessments. It is still only a proposal. If the performance assessments and actions fail to get sufficient generation then there is a backstop auction to make sure reliability is addressed. It is truly only a backstop to ensure reliability.

Question: That is the connection back to the RTO since there's a reliability role there.

Question: In the Argentine model do those who consider themselves harmed by they project have a voice?

Speaker 3: Officially they have nothing to say.

Question: Is this appropriate? A lot of political pressure against transmission projects come from parties who feel that the generation that's serving them today might not serve them tomorrow at the same price if the transmission projects go in and that power can go somewhere else.

Speaker 3: You're exactly right. It's attractive because the core of market theory is free entry and exit. As a seller I should be able to sell my product to the highest bidder. I have problem with someone who says I can't sell my product somewhere else because it will make it more expensive here.

Question: How politically realistic is a 30-30 rule that only applies to beneficiaries?

Speaker 3: They did it in Argentina, built transmission, except when it was uneconomic. I think it's a great thing.

Question: Can I get a clarification? In the Argentine model, the regulator applies the golden rule. Does that mean there has to be net social benefits? It's different than someone just coming in with a project.

Speaker 3: Yes, because they're going to use the regulatory authority to mandate that people have to pay for it. It's an important consideration. The cost benefit study has to be approved.

Question: There can be losers. If it has net social benefits in theory the winners can compensate the losers.

Speaker 3: They won't mandate it. They can go do it if they want to. They've done a lot of things that you'd be surprised. The proposal explicitly does not mandate that you have to compensate the losers. If somebody has a hot dog stand and you want to go build a hot dog stand that competes with them you don't have to compensate the guy with the original hot dog stand.

Session Three.
PUHCA Repealed!! Has Anyone Noticed?

The onset of competition in electricity led many to conclude that PUHCA was a relic of a past era and a major barrier to the emergence of a fully competitive electricity market. More specifically, many utilities argued that the 1930's era statute dictated a corporate structure, business model, and geographic scope that were no longer relevant to engaging in the electricity business in the 21st Century. PUHCA, they contended, prevented the attainment of economies of scale and scope by limiting merger opportunities, reduced the overall level of competitiveness in the market by limiting entry in a variety of ways, and imposed very heavy transaction costs on companies caught up in its web. It also had the effect of keeping many new investors out of the power sector.

Supporters of retaining PUHCA, on the other hand, argued that its repeal would open the doors to the type of financial manipulation that led to its passage in the first place, would allow utilities to put their customers at risks as they diversified their investment portfolios into a variety of business activities in the U.S. and abroad, would lead to frenetic merger activity that would both reduce competition and remove utilities from local control, and would reduce the ability of regulators to exercise the kind of oversight both the public interest and consumer protection demanded.

Still others contended that the SEC's administration of PUHCA was so weak that the statute had been deprived of much of its meaning and, in some cases, had been used to protect companies against market and regulatory risks. Have rules and policies at the FERC and at various state commissions rebuilt PUHCA-like restrictions? A year after repeal, have we learned who was right? What has been the result of PUHCA repeal to date? What will it mean going forward?

Moderator: Our topic this morning is timely. This Thursday at the FERC the commission will be holding a one day conference on whether they properly implemented its new responsibilities and regulatory authority under the Public Utility Holding Company Act repeal of 2006. Has PUHCA repeal caused harm to consumers and markets and competition as people feared?

At some point during the early 1960s the SEC told Congress they felt the primary statutory objectives of the Holding Company Act had been achieved. The primary objective was the simplification of corporate structures of public utilities. In the mid 80s debate about whether PUHCA should be modified to allow entry of independent power producers, or merchant generation. In the end full PUHCA repeal didn't come until 2006.

Speaker 1.

From my perspective PUHCA repeal has had little effect. That doesn't mean that things will change some time in the future but little effect for now and I don't expect it to have much effect. The role of the SEC and of PUHCA have been superseded by state and FERC regulation. This has turned out to be accurate. States have or can get authority to regulate things that were regulated by the SEC.

I'm going to discuss this from the perspective of a large public utility. They have four operating company subsidiaries. They are all vertically integrated with their own generation, transmission, distribution, and independent boards. There is no shared generation among the operating companies. Each builds and owns sufficient power for its operating region. There is an inter-company interconnection agreement that governs a pool run for the four operating companies by the holding company. They met PUHCA requirements by operating as a single system even though it was four separate companies.

In addition to operating the pool they also have a service company to provide shared services such as accounting, finance, external affairs, law, information technology, human resources, etc. They do have to worry about cost allocation and inter-company transactions. They used to have many diversified businesses that have been sold off – gas marketing, energy conservation, etc.

PUHCA had the system integration requirement, and there was open books and records for the SEC. SEC approvals for some things and a lot of paper work to the SEC. Anyone who owned more than 10% of their stock would themselves become a public utility. This may have acted as a deterrent to stock acquisition.

First, diversification in areas that aren't functionally related. There were disasters for many utilities in the 1980s. Florida Power and Light owned an insurance company, Minnesota Power actually bought a company that auctioned used cars. Montana Power bought an aircraft maintenance business. The maintenance business at the Butte, Montana airport was owned by Evel Knievel and Montana Power didn't want him servicing their corporate aircraft so they got into the aircraft maintenance business. Those ventures were a mistake, but most businesses are focusing exclusively on activities directly related to selling and generating electricity.

PUHCA created geographic restrictions on mergers but there utilities were already pushing the limit. For example, the Exelon merger between Commonwealth Edison and Pico, and the AEP and Central and Southwest merger are hard to justify as "integrated systems." They successfully demonstrated there were enough transmission connections but it was a liberal definition. Obviously, Southern California Edison and Baltimore Gas and Electric could never have merged but there's not a big difference before and after.

Mergers will only go forward if they make economic sense and get state and FERC regulatory approvals. To do that they have to demonstrate some savings from one of two areas: synergies and the elimination of duplicate functions in two companies. Achieving synergies with geographically diverse utilities is difficult because it's hard to operate a utility system from a far off location. They will be extremely rare if not non-existent. One exception will be financial players who buy multiple utilities. In this case they will leave those utilities to operate as they always have. They won't merge those systems into a single system.

With affiliate transactions and cross subsidization, an important aspect of PUHCA, the states have developed a lot of expertise. They dealt with them before PUHCA repeal and they will continue to do so. States need to make sure that they have the authority to regulate these issues and ensure it's addressed in their state legislature if it isn't. FERC rules also affect these issues. In the example utility I've been discussing, they operate the same way after PUHCA that they did before PUHCA.

Speaker 2.

I agree with the last speaker on many points. The one difference I see is that the change is incremental and really just beginning. It's a bit early to draw final conclusions. Nonetheless, the protections of PUHCA have largely been superseded by either capital market protections or regulatory protections. The degree of sophistication among the states has increased by several orders of magnitude from 1935 to 2005; they are well equipped to address these issues for the most part.

So far, there has not been a flood of utility mergers, the industry is not in the process of consolidating over the next five to ten years into three or four major national companies. There has not been wholesale diversification away from the utility industry. The capital market discipline is not going to let companies do that. There has not been a flood of highly leveraged companies coming into the market. Both capital market discipline and regulatory protections are more sophisticated than 70 years ago when the statute was enacted.

PUHCA restricted mergers, diversification away from functionally related energy or utility activities, affiliate transactions and regulated capital structures. Out of the five or six transactions announced around the time of repeal, two would have been completed anyway: Duke Synergy and the Scottish Power acquisition of PacifiCorp. The FPL-CEG merger might not have. This was an opportunity for FPL to diversify some of their weather risk in Florida but it got caught up in issues in Maryland as we heard in a previous pane. Two others are being reviewed by state regulators.

There hasn't been a lot of concern over ownership structure and issues of equity interest and outright control. Instead the emphasis is on the merits of the transaction, a sensible approach. If the state regulators decide the transactions don't make sense they'll turn them down whereas if they're approved there won't be a 70 year old anachronistic statute standing in the way of capital flowing into the industry.

There has also been smaller transactions relating to transmission. Some relatively small but important transactions might not have occurred or taken a different structure had PUHCA been in place. The repeal has been successful in that it has brought more interest from large sources of capital to the industry. We will see a flow of new capital into the industry as a result of repeal. There is increased interest from large individual investors, from foreign utilities, and this increases the range of deals that are possible.

The regulators have clearly acted on the repeal. The FERC has done extensive rule making and is about to review the needs for additional modification. Most states feel they have adequate jurisdiction over mergers. They have the ability to review them, condition their approval or deny them if necessary. States have used two categories of regulation to address diversification, affiliate transactions, and capital structure. First, ring fencing, a fairly broad set of rules. Second, a mini PUHCA, the Wisconsin model of regulating diversification and other holding company activity.

The Portland Enron transaction in Oregon in 1997 provided an excellent model for ring fencing. These ring fencing provisions were put in place by the Oregon commission when Enron first acquired Portland and were severely tested when Enron subsequently declared bankruptcy. Ultimately, Portland was downgraded one notch, but otherwise was relatively unscathed. From Portland's perspective there were some minimal adverse consequences but the general view is that those ring fencing provisions served as a good model to ensure that activities at the holding company level don't affect an individual company.

The Wisconsin model is more stringent. I'm not sure if it is good or bad, but it's good the debate is taking place. A real discussion is pertinent to the new landscape. PUHCA was outmoded, its repeal was overdue, the regulatory tools may need some adjustment but overall this will incrementally improve the access the industry has capital.

Speaker 3.

I am not an energy industry professional, I have not spent my career in this industry. I'm a workout professional, an attorney by training. I work as a hired gun for large commercial banks in distressed sectors if one of their lending branches runs into trouble. My background is in merchant power project development.

As many of us know, around 2003 a variety of owners, some associated with larger utilities, and decided to give these credits back to their lenders. Construction was completed on some, others incomplete. Specialists like me were brought in as the banks took title to these assets. The barriers to taking title to these created by PUHCA could have been largely psychological; it's possible that bank management could have been persuaded that this was not a problem. Generally, PUHCA was a huge psychological barrier to the commercial lending community, primarily because of concerns for the SEC. It may sound ridiculous, but they were considering worst case scenarios in which the SEC would come in, assert jurisdiction, and even break them up.

FERC regulation was also an issue. I'll discuss a case in Milford, a small 540 megawatts EWG in Connecticut. It doesn't own anything past its boundaries and has no ancillary services. If anything should not have generated PUHCA jurisdiction, this should have been it. International bank managers were terrified of FERC interference. The flew lawyers to Paris to explain that this was not going to be a problem. There was extensive concern. That's why PUHCA repeal allowed for the development of assets with financial institutions that would have been impossible otherwise.

Lending banks still have to contend with banking regulations that do not allow them to hold an equity asset for more than two years. If it's a debt previously contracted they can do pretty much what they need to do for two years and after that they need to discuss with banking regulators why they're holding the asset.

Originally, they'd go through a conventional merchant banking process. Hire merchant bankers to market projects to one buyer; usually strategic buyers, i.e. utilities, or financial buyers, in it for cash flow. This wasn't working because the transfer of ownership was already happening in their distressed debt market trading.

Previously distressed debt market trading was less liquid and much smaller. Generally large commercial banks would have a hiccup in a loan. They go to a distressed debt trader and a swap is arranged with another large commercial bank. These are called big boy documents, and done exclusively between commercial banks with similar portfolios. However, this has changed recently and the merchant power industry has been a major player. The liquidity in this market has increased dramatically, in large part because of hedge fund money. Hedge funds began to notice these merchant power projects. They began buying debt from the distressed debt of the commercial banks.

Let's consider another deal in Boston where Exelon sold off Boston Generating. 4,000 megawatts of generation, the vast majority of it within the Boston load pocket. Exquisite plants, efficient, and tied right up to a liquid natural gas terminal in Everett. The debt outstanding was $1.2 billion and a replacement cost at minimum of 2.4 billion. A solid $1 billion of equity had disappeared. Exelon walked away from a chunk

and another bankruptcy also occurred. A good $1 billion of real cost of building that project for the citizens of Boston went away.
The lenders wanted their $1.2 billion. Many lenders early on would have sold this debt at 65-85%. There were closed subset of people with $1 billion of cash who are essentially saying, I'll buy your $2.4 billion asset for $800 million because I've got the cash. However, more recently hedge fund money came into the distressed debt market and they started buying up commercial lender debt at more reasonable rates. If the liquidity that was afforded by the hedge fund market had not come into that market that asset would have been traded for let's say a third of its replacement cost.

This could not have happened with PUHCA because of the way these lenders trade their debt. It's traded to evade SEC regulation. The loan documents say that the debt includes equity in the plant. There's a standard document used throughout the distressed debt industry. No one wants to change it so that everyone knows that the regulations are the same and they can trade quickly.

PUHCA oversight would completely interfere with these standard legal documents and freeze this trade in its tracks. The concern for an institution like Citibank or Morgan Stanley or Lehman Brothers who are big players, is that a 22 year old sitting on the trading desk could bid for something that would bring their entire institution within PUHCA regulation. The repeal of PUHCA allowed for this strong liquidity marketplace critical to stabilizing the merchant power industry.

Finally, many commercial lenders were seriously considering mothballing plants that today are dispatching on an economic basis within their marketplace. Had these markets not brought in capital to stabilize this sector, many plants would have been mothballed that are valuable members of their electricity generating community.

Moderator: What is a big boy document? Are they really called big boys?

Speaker 3: Yes. The letter says we are trading between big boys. It's a securities term that means that they have financial wherewithal, expertise; they're not a consumer and they know this trade. It takes them out of retail regulation of securities.

Speaker 4.

I worked to defend PUHCA and to moderate the manner in which it was repealed. I've had a variety of jobs that have involved PUHCA. I've examined the interests of bond insurance companies that thought they were insuring utilities which over time were no longer pursuing utility oriented activities and having to address credit downgrades. There's all sorts of reasons that PUHCA helped clarify interests and roles.

Diversification with financial players has been a concern as well. The Westar and Northwestern cases are good examples. I have been a proponent of ring fencing also, one way to handle the issues created by PUHCA repeal.

Utility diversification in which awkward situations where utility and non utility ventures have trouble co-existing in the same corporate family can be a big problem. For some companies the temptation to cross subsidize and to engage in affiliate abuse has been like the temptation that one has when you see a $100 bill on the street. If not me someone will pick it up, why not me?

Before repeal PUHCA wasn't being enforced by the SEC in the way I it was intended. The statute was being administered by an agency that did not believe in it and actively promoted its repeal. PUHCA was very restrictive. There were certain things you could not do or could only do with difficulty. It didn't allow certain corporate structures, activities, transactions and essentially wanted a utility holding company to be an integrated system involved in no other business. Changes had to be made to PUHCA in order to allow certain kinds of activities to occur. However, regulation by FERC and the states is still relatively untested. There is a possibility of enormous complication of corporate structures and transactions with no clear answers on who will be looking at these issues for potential harms to consumers.

A recent article by Scott Hempling for the Electricity Journal on PUHCA repeal examines 70 little regulatory issues and actions. He notes that PUHCA repeal does not clarify what should happen with these situations. It's likely the states will have difficulty anticipating and putting in place legislation that they may need. The states often had difficulty, and found that their statutory authority was less than they thought once in court.

The tradeoff made legislatively for PUHCA repeal was enhanced merger authority and books and records authority. The major constituencies were satisfied by that compromise. However, there are cross subsidy issues that are not evident at the point of a merger. FERC has declined to say that they will require ring fencing. At the time of a merger there's no way to predict what the problems will be. Books and records are a fine record of what's already happened but don't prevent harms from occurring.

Currently, the markets have disciplined the desire of players to engage in some of these problematic activities. Credit agencies have been hard on diversification, to put it mildly. They have exercised market discipline in giving directives to utilities that this business is too risky. People are really getting back to basics. However, I'm concerned this will pass and new strategies will come in place.

Some states have taken an activist stance that has lessened merger enthusiasm. There is not a whole lot of new legislation to replace PUHCA so states will be facing new complexity, trying to fashion remedies to address it. It's the tendency in those instances to over-correct; to address the case in front of you but not underlying structural issues. They may actually restrict mergers that ought to occur.

One of the major reasons for PUHCA repeal was so investment could come into the utility sector. As the panelists have discussed, that has been true in some ways. However, to a large degree we have not seen some of the promised benefits to any major degree. It is too soon and there is a semi chaotic state of regulation due to the transition to competition, the coexistence of regulated and deregulated activities, some policy initiatives at FERC, etc. It is not the best climate for investment.

Certainly, nothing terrible has happened since PUHCA's been repealed but it's been less than a year since repeal has been effective. Less than a year after EPAC92 it was not yet evident the amount of stress that would come into the merchant sector. The EWG exception, the foreign utility exception to PUHCA, and the telecom exemption in the Telecom Act of '96 all created difficulties that were not immediately apparent. Certainly, I hope the others on this panel are right and good things continue to happen.

Moderator: In the years leading up to PUHCA repeal, there were extensive debates all over the country. Now that repeal has occurred we are going to have many of those debates at the state level. It's like Act 2. In the context of making markets more efficient and competitive to benefit consumers, PUHCA repeal is important. However, there is still concern that repeal is a great problem for consumers. This is the issue facing state regulators.

Clearly PUHCA was a barrier to entry, to investment, to new companies and new infrastructure. It can't all come from utilities – their balance sheets are not large enough for the new investment necessary. Some of the structural changes discussed in the context of the RTOs could not be contemplated if PUHCA was still on the books. Certainly, the jury is still out on whether all these hedge funds and private equity can make these markets and companies more efficient.

Today we have 3,000 entities that supply electricity to consumers. This is not optimal. Clearly some consolidation would be useful. So the question is how do we strike the right balance on the consumer side? Ring fencing is a powerful option.. An important point earlier about the FPL-BGE merger is that one person's efficiency is another person's cross subsidy. That is an important issues, it could be the crux of how to think about the post PUHCA environment.

Determining what types of ring fencing provisions to put in place through new legislation or new activity under existing law is an important task. The right balance is critical. If they go too far then the promise of investment, entry, and efficiency gains will be lost. If we don't go far they will have failed the consumers. I recommend that people read Warren Buffet's affidavit that he was required to give in the Mid America purchase of PacifiCorp. It is a breathtaking affidavit that goes far beyond the conditions that made up early ring fencing contracts. Here is Mr. Corporate America, and he makes promises that the transaction was in the public interest, he will restrict exercising managerial discretion, bringing expertise, and allowing the utility to remain under local control. It's an example of going too far. The affidavit says they don't want his expertise, managerial judgment and capabilities. This loses the promise of PUHCA repeal.

Question: One of you declared that much of what PJM is doing or considering couldn't happen without the repeal of PUHCA. Could you expand on that?

Moderator: This involves restructuring the difference between its energy markets and its transmission function and separating out on a structural basis. It's still evolving.

Question: However, we were told that definitively will not happen.

Moderator: The fact that it was even being discussed could not have happened if PUHCA had been on the books.

Question: I wanted to respond to the final thing said concerning the states. When PUHCA was repealed many said the states are in a good position to protect consumers. Sometimes we see overreactions like the Warren Buffet anecdote however Kansas is going through a rule making because of the experience that they had with Westar.

Not all mergers and acquisitions are the same, whether to impose ring fencing and what kind needs to be determined. We saw real problems with M&A in telecom. Think about Qwest or U.S. West – real problems. Pension funds were looted, debt was leveraged extensively. There's valid concern for how to go forward.

Speaker: Yes, there has to be some balance and the states need to look at what authority they have. Perhaps some overreaction is appropriate, I just hope there's not too much overreaction that we start to lose the efficiencies that we thought we were gaining by repeal of PUHCA.

Speaker 4: Ironically, Warren Buffet ring fenced even before his acquisition of Pacific Corp. He has always ring fenced. Although he has been a major proponent of PUHCA repeal, he diligently ring fences all of his utility assets as part of good corporate governance. It's a real prophylactic for potential abuses.

Speaker: Mr. Buffet is an unusually hands-off investor. One, he has confidence in his management. Two, he has confidence in his ability to persuade his management even though he may not have legal control that permits him to force them to do something. Three, he truly understands that he really does have control.

Normally investors want a litany of three dozen veto rights when they look at an acquisition, especially if they are new to the process. In Mr. Buffet's case, he only wanted a handful from the SEC. He is less concerned with some of these control issues.

The Pacific Corp ring fencing had extensive assurances because there are unique elements in the holding company that allow for it. Not all companies are in a position to provide the same levels of assurances. Everybody wants a stable industry with ready access to capital. We want a structure that permits whatever the agreed upon consensus is to move forward with the least restriction from a statutory perspective. The '35 Act was too blunt an instrument. We need more refined ways to prevent bad company decisions.

Moderator: Warren Buffet has been doing ring fencing for a while. What struck me about his last affidavit was it had gone further than before and it becomes a model or starting point for other deals as we go forward. Those kinds of conditions may be excessive.

Question: Could you discuss the plants in Boston further? For $1.2 billion you get $2.4 billion replacement cost, pristine plants with the latest technology hooked up to ready supplies of fuel in a load pocket. Were they in bankruptcy; why were they turned over?

Speaker 3: They weren't in bankruptcy. A site sold Boston Gen to Exelon some time back. They were having difficulty completing construction; two years overdue but the lenders continued to forbear and extend time on this – they weren't concerned.

The contract to build Boston Gen was a fixed fee contract. When it went over budget Raytheon had problems. They sold the contract to a bank that was unaware of the depth of liability in the contract. The bank had to file bankruptcy. A judge quickly ruled that a performance guarantee by Raytheon required they complete the project. It cost $1 billion more to construct than originally contracted for.

There were arguments between the construction contractor, the bank, and Exelon that needed to be resolved to the tune of 200-400 million dollars. However, S&P issued a press release saying that Exelon would be downgraded if they put another penny into the project. The ratings agencies had been very concerned about non recourse deals such as this; if they put more money into it then it wasn't really non recourse. So Exelon simply decided to offload it. The knew at least 200 million was needed to complete it. This caused a bit of a fracas that went to the advantage of the lenders. Exelon put in some extra money and Raytheon settled their claims and went away. The lenders, because they were the secured lenders, could put the project in bankruptcy and eliminated any of the contractors' claims. This enabled the lenders to negotiate with the contractors in a way others could not and successfully gain leverage.

The S&P concern was valid. Exelon viewed the site as worth more than its debt, a valuable asset. However that much debt on their balance sheet depressed their stock price. From the point of view of S&P, the income stream didn't justify the debt level for their corporate purposes.

Question: OK. Either the debt level is too high or the income stream is too low. Or that S&P was wrong.

Speaker 3: In project finance, when you're building a large, expensive asset, it doesn't have to be a power plant, it can be a road, that doesn't have an immediate revenue stream to offset a large amount of debt it is viewed as a problem on a corporate balance sheet in the current market. There may be some disagreement there between utilities and finance – a different view and focus. There was a concern for a depressed income stream, a price spike in natural gas, etc.

S&P was concerned that Exelon would keep dumping money into the project.

Question: What's going to happen with affiliate contracts? For instance, the Ohio Power case was way above market and essentially insulated AEP from market pressures in the coal market. Are these agreements open? Are companies with above market contracts with affiliates still protected from market forces?

Speaker 1: Many utilities will continue to conduct affiliate transactions at cost. Some will say that if cost is above market then they ought to end those contracts and go to market. However, the chances are just as good that cost will be below market and the administrative difficulty of going out for bids could be cumbersome. FERC looked at this issue and decided they would not require utilities to go to market. The administrative costs of having to figure out the market price of everything we do on an inter company basis. So I think continuing to do transactions at cost is the right way to do it.

Speaker 4: FERC is loath to break existing contracts really in any circumstances. One worries about utilities that don't have a good history of supply and contracting wisely. The degree of state level review can be good or bad. When a utility does business with itself questions can arise.

Speaker 2: FERC is going to review a subset of contracts soon that come under pre-repeal SEC authorizations. There is some review. Some of them they will grandfather, and others they will review again at the end of '07. FERC acknowledged that they didn't know the full complement of SEC authorizations. They'll review many of them on an ongoing basis, nothing permanent.

Second, with Ohio Power the concern was that SEC approval pre-empted FERC or the states from reviewing the contract. Without PUHCA that is not a problem.

Question: State commissions always have budget pressures and have to determine where to place their priorities. In areas with federal regulation but not preemption they will back off because there is a body of federal regulation at least touching the base. Under PUHCA the SEC had light handed regulation but state commissions were still probably not paying a great deal of attention to these areas, simply because of the appearance of regulation by the SEC already. I expect state level regulation in some cases could be stronger. Mini PUHCAs, aggressive ring fencing etc. Even though there may be a consensus that the industry has to grow, I'm not so sure that's going to matter to state commissions when they're looking at protecting their local utility.

This macro issue is a concern. If there is a patchwork of states, mini PUHCAs, ring fencing rules, and multi state multi jurisdictional entities with few common denominators, we may have a morass. No longer a psychological barrier to investment but a new regulatory barrier to investment? Will this occur?

Speaker: A legitimate concern is that the solution might be worse than PUHCA itself. In the PacifiCorp transaction they used a mechanism to get some states to sign off earlier. They provided an endorsement that if additional protections were given other states after the initial state had signed off, then they would all get them. Now they have six states with uniform ring fencing. It's a serious concern but I have faith in the regulatory process and in companies to think this through rationally. Regulators and companies are trying to be responsible about what they're doing. Unwieldy complexity could be a problem; there is a half deregulated, half traditionally regulated structure at the moment. For mergers and ring fencing there will be a gravitation towards a rational set of provisions. States have to determine how to obtain the benefits of mergers while not exposing their companies unduly to risks of mergers.

Speaker: The Repeal Act did recognize that utilities might run into problems with cost allocations across state lines. It gives utilities the ability to go to FERC to preempt the states on cost allocation.

Speaker: There wasn't that much preemption in PUHCA anyway. There was a perception that it occurred a lot but it really didn't. If a utility in a state utility rate case tried to claim that a cost had been preempted by an SEC allocation one of two things happened. Either the state commission would argue the SEC only approved a general cost allocation formula and never sought to preempt state regulation. In fact, the SEC was saying these cost allocation formula are general formula and the inputs are subject to state review. The SEC had disclaimed preemption.

Alternately, they would do what sophisticated state regulators do on a regular basis. They'd say, "if you want to argue preemption you've got to recover X dollars of these service company costs. Oops, we just realized that the return on your distribution is going to go down 11 basis points. Oh, that seems to offset the preemption costs. That's fine, go ahead and assert preemption." PUHCA preemption was not the great preemptive sword that people thought it was.

Question: My main point is not that there was preemption but rather that there was regulatory forbearance because there was a statute out there. A commission has other more important things to do if they can rely upon federal oversight and kind of look the other way. One regulator was concerned about utility participation in a money pool but it would have been a great deal of work to oversee this. Suddenly they realize that there is also SEC jurisdiction over this so as a regulator I can walk away.

Speaker: Certainly, but on a lot of the bread and butter cost allocation issues, especially with service companies and the formulas, the preemptive effect of PUHCA did not lead to that kind of forbearance. I do agree, a mess is possible.

Question: The electricity industry is probably the least consolidated major industry in the United States. Could the panelists make some predictions about what level of consolidation they see in this industry ultimately? What will be the impact of this consolidation on consumers, regulators, or the general public good.

Speaker 4: This is a period of uncertainty and shakeout just as with other major changes made to PUHCA. States need to discover what they can and cannot do, and more aggressive players will test boundaries. There will be a shakeout that occurs in the context of regulation versus markets. My hope is that we'll come out with a model that is more market oriented than regulatory, because I believe markets have much to offer to consumers. They have to be true markets and not the kinds of quasi markets that we have in certain parts of the country.

Speaker 3: This is not my industry. At minimum we can expect a certain level of consolidation that will push towards a more market based system. There's extraordinary economic inefficiencies in a number of markets. With consolidations and financial players with some weight, these inefficiencies will not be tolerated.

Speaker 2: I'm not sure about the markets question. In 20 years the industry will still be in the process of consolidation. There are significant benefits. However it will be a gradual movement in that direction because there are a lot of issues that need to be resolved. There will be fits and starts with a steady consolidation, but not a dramatic flood of mergers over the next 20 years.

Speaker 1: I agree. RTOs were formed to gain a lot of efficiencies that could have occurred by merger but didn't. A lot of the economics driving mergers dissipated because RTOs eked out those efficiencies of all those small systems. There isn't going to be a whole lot more consolidation. Generally, it's going to be just in the generation sector. We'll probably have fewer companies that generate electricity but many distribution companies because there's not a lot of economies of scale in distribution. With transmission there is, but it's so politically sensitive that it's difficult to achieve them.

Moderator: This will happen in two or three ways. One the dust settles from FPL and Constellation, and Exelon and PSEG and we'll still see 1-3 significant IOU mergers a year for the next five to ten years. At a certain point the efficiencies will begin to become more difficult. Geographically disparate mergers will still be a difficult sell to regulators in both places.

The bigger efficiency gains are at the smaller IOU level as well as the muni and co-op level. There's a strong tendency not to do any consolidation because of local political and financial issues. I do expect there will be some consolidation.

Finally, the mid to small size local gas distribution companies are good candidates. There's many small states with four or five local gas distribution companies. This is probably not the right structure to deliver best service as well as efficiencies to consumers. The mergers amongst IOUs will start up again at a modest pace once the dust settles but the important activity needs to be focused on these other sectors.

Question: One argument we've seen is that cheaper capital is possible if the state utility guarantees that ratepayers are going to pay for the asset. That's the argument to have the vertically integrated utility build because they get cheaper capital. Alternately, the nuclear experience seemed to increase costs prohibitively. Will we have a competitive sector with private sector investments or will we go back to the ratepayers as the guarantors to lower the investment? Does repeal signal any changes in that or is this just a different topic?

Speaker 3: The structural changes in the merchant sector and there's a class of non municipal financial investor in what was originally the distressed market. Now different groups of them have formed companies and organizations to hold and manage them. This is new business. So in merchant generation there's no question they're looking to acquire and consolidate those holdings. I expect several large financial entities will become fairly expert at owning and managing more consolidated holdings and merchant deals. They will be hard to compete with. They will be available when one is ready to construct new plants.

Question: They can outsmart big utilities?

Speaker 3: Not necessarily [laughter]. But there is a new group of owners and operators and they're not going to go away unless there's some strong legislative program to fund these plants another way.

Speaker: The days of utilities rate basing plants and putting the risk totally on customers are gone. Utilities will build plants and put them in rate base via an RFP process where the up front price will go into rate base and utility shareholders take the risk. The one exception may be nuclear. No one will take that risk other than by placing it on the customers. Other than nuclear, markets will decide the winner; a utility RFP going into rate base or an IPP.

Question: Can the utility get cheaper financing?

Speaker 1: No, not necessarily. Utilities might be more limited in their flexibility than a lot of financial players because they have debt equity ratios to meet. Other people can project finance or use more debt, so I don't think it's necessarily true that the utility will be the cheapest cost to capital.

Speaker: Even if the utility could, why would that be bad? Wouldn't that be sending a signal from the market?

Question: If you do the RFPs correctly that's fine but that doesn't always happen.

Question: PUHCA repeal has brought new players into the market, certainly. However, states are very nervous about where new capacity is going to appear. Trends go both ways with nuclear and IGCC.

Speaker: Wind and demand side management are also difficult.

Question: Yes. Capacity markets and rate basing are mechanisms to entice people into the market. However we have failed to attract entrants into the competitive markets and not in the ones where prices are lower?

Speaker: The lack of long term contracts is critical. Vertically integrated players have the ability to do long term contracts with IPPs or affiliates. Seven year contracts, not 20 or 30. Here, nuclear is an exception. Nuclear needs a 20 or 30 year contract. I believe it's OK to make exceptions to the competitive model for socially good reasons. If we want to get off of oil and gas in this country we have to build nuclear. If rate basing is the only way to do it we should.

Question: So far PUHCA repeal has only attracted folks to low hanging distressed fruits, but not to capital intense long term investments. The door is open but we have no entrants.

Speaker: No single utility is able to finance a new nuclear plant. There's consideration across the country to financing structures with multiple players, old and new.

Question: I'm not talking about a specific technology; building more CTs is the same kind of thing.

Speaker: Putting all the risk on the ratepayer or the utility shareholder hasn't worked. We should see different types of investment with joint ventures and co-ownership arrangements. These can address the problems. There hasn't been enough time for them to play out.

Question: Will new nuclear plants be sole sourced?

Speaker: That's still an open question.

Question: Why would they be sole sourced? A decision is made by some process other than an RFP that Westinghouse is going to build the nuclear plant and not GE, or Entergy will, not Southern Company.

Speaker 1: I don't expect utilities will switch from Westinghouse to GE, or vice versa. The model will be different than before clearly, they will be much more careful.

Question: Will a utility go to other parts of the country other than their region to build nuclear plants with their comfortable partner?

Speaker 1: No, their service area is the only place they can rate base.

Speaker 2: The risk profile for an existing combined cycle gas facility compared with the risks associated with building an IGCC facility or a nuclear plant where the capital costs are dramatically higher. There's enormous technology risk. The lead time is 5-10 times that of a gas plant. Construction risk is enormous. Hedge fund money does not think in those time frames and they do not have the level of confidence to pursue these kinds of projects. GE will warrant turbines but they won't warrant gasification technology. There will be significant liquidity differences in these markets.

Question: New generation has many issues that haven't been addressed. There's a real inability to predict gas prices out 20 years so it's difficult to make fuel choices. In both IGCC and nuclear the technology hasn't been built recently, or at all. There's uncertainty there. There's been cost overruns for IGCC plants even before ground has been broken. Finally, carbon trading brings extensive uncertainty to this landscape. There's phenomenal risk associated with these decisions on the part of any investor, traditional, non traditional, new entrant.

The state of the market reports in the organized markets all say there isn't enough revenue to support new investments. We believe we need new capacity and yet the markets are sending a clear price signal that investment isn't needed. There are extensive challenges for the industry.

Speaker: The solution is to fix the revenue problem and then find out whether the investment really is needed. We do need the right price signals. PJM is aware of the problem and working to fix it in other venues outside the strategic planning forum.