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HARVARD ELECTRICITY POLICY GROUP
FORTY-SEVENTH PLENARY SESSION

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RAPPORTEUR'S SUMMARY*

Session One.
Ample Opportunity, Ample Risks: The Dilemma of Generating Companies Trying To Make Prudent, Needed Investment in the Context of Climate Change Uncertainty.

In the electricity generation market, debate over climate change is not theoretical. The debate is practical and pressing. Demand will outstrip supply in many parts of the country and there is a great deal of capital available for financing new generation. The problem is that most resource options contain significant risks. While renewable options are attractive for a variety of reasons, a number of the technologies are not economically viable, and wind, where it is viable, is not available in sufficient quantity to meet the needs. Natural gas prices are highly volatile and some have raised serious policy concerns that the U.S. has become too dependent on natural gas. Oil is less than desirable for both environmental and geo-political reasons. Nuclear is still fraught with risks from a political/public perception, waste disposal, and perhaps other perspectives. Hydro potential has largely been tapped. Energy efficiency is always a good idea, but, alone, will never satisfy the nation's need for energy.

That leaves the abundant coal resource. Looming over coal is the enormous uncertainty regarding climate change and the direction the country will be taking in regard to CO2 emissions. Technologies that might be employed to render coal more environmentally benign, such as IGCC and carbon sequestration are either not economic without subsidies or are technologically unproven. How should companies approach building new generation, and how, specifically, should generators be looking at coal? How should the owners be dealing with upgrades and major maintenance at coal plants whose viability and useful life may come to an abrupt end as a result of restrictions being imposed on coal plants? What is the prudent way of dealing with both prospective and existing coal units?

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

Moderator.

I'll start with a quick recap of where California has been because they have been leading the way in climate change legislation. The centerpiece legislation has been AB 32. It requires reducing emissions to 1990 levels by 2020. AB 32 just sets a broad framework and broad targets. There is a lot of work to define how compliance will work, how allocations will be determined, the overall framework.

There is also SB 1368 that limits procurement in the state, not allowing any commitments greater than five years for rights that do not meet the CCGT Emission Standard. The standard itself is a little fuzzy. Importantly, initial studies showed this legislation would be costless, or provide a net economic benefit. However, recent studies by EPRI [Electric Power Research Institute] show a cost for technologies that help control climate change. Their estimate is $100 to $500 billion in costs. $100 billion for market-based approaches versus a higher range for a command and control approach that seems to be favored by legislators.

At the federal level, the new EPRI Prism analysis starts off with an EIA [Energy Information Administration] baseline that incorporates assumptions about technology needed to meet some targets. Whichever federal legislation is adopted, it will take significant technology investments and enhancements to achieve goals. Second, no one technology forms a silver bullet. Solar, wind, energy efficiency:- contributions from multiple technology sources are needed to get there. The biggest carbon reductions are expected for carbon capture and sequestration after 2020.

There is still significant cost. Depending on which legislation is adopted nationally, the EPRI study shows a $1 to $2 trillion change in GDP through 2050. If advanced technologies come into play quickly and effectively then that may be cut in half. Nonetheless, addressing climate change is going to have a massive impact on the economy, on infrastructure, and on technology needs.

Speaker 1.

We are in the beginning of what could be a perfect storm of significant climate change. Further, if we don't change our generation technology mix, we are also on the brink of reliability and price problems for our economy. We need new generation. These three problems together are a real challenge for our political and decision-making infrastructure.

A year ago the top trends in power generation industry dynamics were mergers, the credit market, implementing capacity markets, reserved margins, gas, the right generation mix, and whether there should be long-term PPAs and how they happen. Many of us are still engaged in that. Carbon was important but low on the list. This year the top ten items are all carbon. This is a once in a generation paradigm shift.

Can the industry maintain reliability requirements, and build the 200 to 300 gigawatts of new generation needed by 2030, and meet carbon emission targets that are necessary and going to be legislated in this country? Can they also keep national and global economies vibrant? Further, can this be done without a return to command and control cost of service regulation? Can they keep using coal? My answer is yes, so let's talk about how.

The approach to the carbon issue that I will discuss has three prongs. The first is to support effective climate policy in the United States and internationally. Many companies have begun to take part in organizations such as U.S. CAP [United States Climate Action Partnership] or work with international groups of businesses such as 3C [Combat Climate Change] to address these issues. U.S. Cap includes environmental groups and creates a policy framework and advocacy platform. They have a scaled up Washington presence and are working aggressively to get climate change legislation passed quickly.

The second thing is to manage price risk. Some have joined the CCX [Chicago climate exchange] and are buying and selling offsets. This kind of carbon marketing and risk

management should become general commercial business for all companies.

Third is to advance new low carbon technology. There have been very recent applications to the Nuclear Regulatory Commission for the first operating license of a new nuclear plant in the United States since the 1970s. This is a 2700 megawatts advanced boiling water reactor in South Texas.

There is certainly going to be legislation passed. That policy world drives both risk and opportunity space. There is broad consensus publicly, and amongst almost all world climatologists that climate change is real, that human emissions will do serious damage to ecosystems and economies if we exceed atmospheric concentration levels beyond a consensus of 450 to 550 parts per million.

If the Greenland icecap melts appreciably, it will accelerate glacial flow into the ocean, raise ocean levels and change the contours of our continent, the Indian subcontinent and elsewhere. We're looking at species loss; POLR bears are likely to suffer declines in population. Coastal flooding and extreme weather affecting the world's poor and developing nations disproportionately. How do we avoid this?

How do we turn down the faucet? Business as usual emissions globally are at 7-gigatons of industry-based carbon and will double by 2050. There are four approaches. The least stringent approach is "business as usual" till 2020 and then require constant reductions. The second is the most stringent, to implement immediate constant reductions. The third option is to slow, stop and then reverse emissions. This would allow for some increase in the near term. Last is an option to flatten and then reduce; i.e. to allow for no increases and then implement reductions by 2025. This is like the wedge approach advocated by Dr. Socolow and Pacala.

The rapid development of carbon capture and sequestration [CCS], and nuclear technologies will make path number 3 or 4 much more effective, acceptable, and less costly to consumers, economies and politicians. Considering what kind of policy allows stakeholders to think about how they wish to influence policy and also to allow them to form expectations. What kind of price paths come out of the different emission paths?

A relatively modest cap gets the low hanging fruit, intersects with minimal carbon reductions and has a low price. More aggressive reductions change that equation obviously. If we have new technology innovation, the supply curve shifts to the right and allows aggressive reductions at a lower price.

The path forward should have modest initial carbon caps but include strong policy support for jumpstarting low and no carbon technologies, especially CC&S. Much more aggressive caps are implemented later after the new technology is ready. This allows the 450 ppm goal to be achieved by mid-century.

Congress is not yet advocating this approach. Broadly, there are two different schools: Bingaman and Lieberman. The four variants are the Bingaman discussion draft, Bingaman-Specter, McCain-Lieberman, and the Lieberman-Warner white paper being turned into legislative language right now. All have aggressive caps, with most reductions up front and more aggressive reductions later. None of them has a "flatten and reduce" or a "slow, stop, and reverse" approach that allows for the implementation of technology in about ten years.

Let's consider what prices these might produce? It is certainly difficult to determine where the supply curve is and forecast prices. Nonetheless, the EIA conducted an analysis of the McCain-Lieberman bill. It forecasts carbon prices in the mid teens initially and goes to almost $80 per ton of CO2 in nominal terms by 2030. Bingaman-Specter has a safety value that keeps prices to around $30 per ton in 2030 and around $50 in 2040. The Bingaman discussion draft has a lower safety value. What doe these prices mean for a power producing business?

If one analyzes dispatching for coal and gas, gas plants begin to dispatch before coal plants as soon as the CO2 price hits $20 per ton. This

assumes forward prices for gas at around $7. As soon as carbon prices are above $10 and gas prices above $6, it becomes cheaper to run a combined cycle seven heat rate plant than to run a 12 heat rate coal plant. Coal plants run the gamut between 9.5 to 12 heat rate. Prior to $10-20 carbon prices, there won't be any difference in terms of coal utilization or carbon emissions from coal or gas power plants. It will just make the price of coal and gas power go up a little bit. Once we see higher carbon prices, there will be more incremental dispatches of coal plants off and gas plants on. When more gas is used in response to these higher carbon prices, gas prices will go up.

In this scenario, an equilibrium could easily occur with existing technology where there are higher gas prices, higher power prices, but still only minimal reductions in carbon emissions. Politicians really don't want to explain why the power bill went up a lot so we could turn off carbon, but carbon was only reduced a tiny amount. This suggests, from a policy perspective, strong pressure to eliminate carbon and to gain base load technologies that are immune to carbon pricing and also to gas substitution. New low carbon technology is key: politically, economically, and environmentally.

The emission path to 450 ppm requires industry to avoid about seven gigatons of carbon globally that will be emitted, on top of another seven gigatons already being emitted, by 2050. Five-fold growth in global nuclear output reduces two gigatons out of that seven. If wind is tripled globally it only reduces about one gigawatt of carbon. There is no silver bullet.

All of the pieces are needed. The most important being carbon capture and sequestration, and nuclear. These are not ready to be globally implemented at low-cost, or with high levels of penetration and success. Thus a moderate CO2 price until these technologies are ready is important. Further, there should be robust, strong target incentives to get them ready.

The key elements for a successful climate policy include national cap and trade with gradual price escalation that includes modest caps early and a safety valve. Some allowances should be allocated, not to create windfalls, but to buffer a compliance customer's carbon emitters from negative impacts on their balance sheet and allow them to invest in new low carbon facilities. there should be decentralized incentives for geological sequestration so that having friends in the government isn't the way you get a location sited. so you don't win with a new project just because you have good friends at the DOE or at some agency some place. The rest of the allowances should be auctioned to create a pool of revenues to buffer negative impacts on others and to support programmatic funding for geological sequestration, CCS and other technologies. Fast-track permitting for geological sequestration and enhanced incentives for nuclear are the final pieces. These are necessary and there is a real chance of consensus on all of these, and consensus quite early.

What does this mean for a generator's investment strategy? First, consider policy outcomes and price in every investment decision. Second, look at each market's price signals in terms of fuel mix, fundamental analysis, and customer needs. Generators are competitive companies with no rate base and shareholders to answer to. They have to consider the forward curves of the market for fuel, power, and market design. What fuel is on the margin? Gas or oil? Who is going to enter or retire? A diversified portfolio reduces carbon risk. Finally, development risk has to be addressed carefully.

Let's discuss that in the context of nuclear. There are six key risks in the nuclear business. Regulatory risk. You have to get cozy with the NRC. Getting EPAct standby support and doing things like early filing of a COLA (construction and operating licensing application) can help. Second, merchant risk. There is a lot of money that must be backed at market prices over a long period; it could go up or down. Gaining equity partners, using long-term off-take agreements, and the EPAct production tax credits can all help mitigate these concerns. Political risk. Not everybody loves nuclear power. Working with state and local officials is critical. Financing risk. $5 or $6 billion require making debt lenders

very comfortable to get a good deal. It also helps to work closely with suppliers and vendors. Fifth, technology risk. Facilities have to work properly. One wants newer technologies that are still established enough to have a track record. In nuclear, ABWR [advanced boiling water reactor] technology, which is the only new technology eligible for EPAct incentives that also has actual design certification operational units that have been delivered on time and on budget. Completion risk. Facilities have to be finished on time. Using a turnkey contract with an experienced EPC [engineering, procurement and construction] provider to make sure that it gets done can help a lot. This is the way to handle nuclear risk, via classic project finance techniques.

Let's look at what a realistic low-cost low-carbon development path would look like in the Texas context. Currently, it has about 70,000 megawatts of peak load and reserves, increasing to 110,000 megawatts at 2024. Recent plans for 11 new coal plants just fell apart. Gas investment is now emerging. Limited coal investment can be expected, consistent with the ideas in the environmental defense and NRDC settlement with TXU. One could expect initial nuclear and experimental IGCC to come online around 2014/2015. A couple of years after that one could look for new investment in base load to be a combination of nuclear and coal with CCS. This allows for 37 gigawatts of new generation and only 60-70 million tons of carbon per.

This can be done. The industry can reduce carbon intensity and emissions. They can increase fuel diversity. They can have base load power when and where we need it. They can have strong incentives for resource allocation and risk in generation development. Leadership is the crucial missing piece.

Question: I recently read that the Sierra Club, NRDC and others have a formed a new coalition to fight nuclear plant loan guarantees in Congress. This would create a serious barrier, if not entirely eradicate the nuclear revival in the country. What is the generation market going to do?

Speaker 1: One of the big wild cards is how powerful and effective the anti-nuclear lobby is going to be versus the pro-nuclear lobby. I expect companies will work closely, and with the Nuclear Energy Institute to keep pressure and enthusiasm about the loan guarantee at a high level amongst members of Congress, especially committee members and also in the administration. I think there is a broad understanding of the value and need for the loan guarantee program there.

Question: Who is on the other side of long-term off-take agreements with nuclear plants? Utility companies, load serving entities? Please comment.

Speaker 1: They can include utilities, LSEs, municipal entities, public power entities, and consortiums of larger customers. They can generally be expected to be wholesale customers who can access the grid.

Speaker 2.

I am going to discuss this issue from the perspective of a large utility emitter. The biggest of these companies put out more than 100 million tons of CO2 per year. We've seen such companies come out in favor of cap and trade, and also for a carbon tax. The thing they need the most is to determine what the legislation will be.

Most of the bills in Washington do not have a slow stop and reverse trajectory that I advocate. Instead, they have a step-change reduction immediately and go down from there. These require big immediate fast reductions, a nightmare scenario for large utility emitters. Certainly the utility sector is the source of the cheapest emissions reductions but they are a little bit constrained in terms of what they can do right away. What can they do quickly?

Three immediate options are offsets, new technologies and behavioral changes. Offsets are really up in the air and there is political debate about whether they should be allowed. Further, the Europeans are out there already in a much

higher price market. Any price in the international area is going to be higher than in the U.S. at least initially so this is not so helpful.

New technologies simply cannot be deployed quickly. We can't expect gigawatts of new wind, IGCC with CCS, or a fleet of new nuclear plants. or whatever. 30 years ago we had phones with dials and now we've got Blackberries. The same thing will happen in energy.

This leaves behavioral changes. There are lots of things to be done: change light bulbs, HVAC systems installation, drive smaller cars, carpool, take the bus, move closer to work, etc. However, asking people for an immediate step change on day one is not politically feasible.

Where do we get reductions? Offsets, power sector, and transport. It's a question of less valuable versus more valuable. Emission reductions on an agricultural waste lagoon are not very valuable and there is an easy incentive to do that. Driving a car to work or flying to a business meeting is high value. People will continue to do that.

In the power sector, quick technology reductions can only realistically get 1% to 5% in the first 15 years. This involves efficiency tightening in the existing fleet and throwing biomass into the boilers; that sort of thing. There will be no big reductions until big deployment of new technology comes into play. There are 1,500 coal plants in this country. This will take time. I expect that by 2050 or 2060, all those plants will be gone. That begins to happen at a price range of about $25 to $45 per ton CO2. Big transportation reductions don't occur until much higher CO2 prices come in. The consumer is always the source of most reductions.

Carbon intensity in different states' economies varies considerably. Carbon policy will hit certain areas much harder than others. The states with the most interest in going forward with CO2 have the least economic interest in coal, oil, or other carbon sources.

Electricity rates may be affected, depending in large part on the degree of allowance allocations in new legislation. If the industry is lucky enough to get 85% allocations this results in $25 carbon prices by 2025. This is the sweet spot when commercial deployment of carbon capture and sequestration can be expected to kick in.

This kind of allocation will result in small rate impacts. Fewer allocations will significantly increase rates for consumers. However, a big allocation will still ensure that consumers see a price signal. Price increases will still be being implemented simply because the industry will be making substantial investments in lower emitting technologies to pre-empt increased carbon limitations coming in upcoming years. The allocation acts as a damper on the price signal. If there are no allocations then the consumer is paying for emissions credits, and they are also paying to capitalize investments to de-carbonize. Really, they should only be paying for the investments.

Some thoughts on coal and natural gas. First, we have the coal fleet we have, good or bad. The industry cannot replace them immediately. Second, as carbon prices increase gas will be increasingly dispatched, which will increase price pressure on it as a fuel. Since natural gas is constrained, we may see significant cost increases with little coal use reduction. The coal-gas balance may change very little.

There will be a lot of older, very small units that will retire. The majority of the base load units in the fleet will continue to operate. The gas price increases will drive a fair amount of industrial demand out. At the same time the modeling I've looked at shows that the dispatch order will be little changed.

If there are price spikes and an unraveling economy then we should seriously consider safety valves or some sort of cost control mechanism. A fast reduction will be virtually impossible, so there is a real possibility of price spikes. If there's a very hot summer across the country, and perhaps the economy is humming along – similar to the summer of 2000. In this kind of situation every unit in the region is running very hard. In this kind of scenario one can easily see natural gas and carbon chasing

each other up in price. 250% price increases in coal states could easily occur in this kind of situation. Neither one can back down because of the electricity load. Further, because it's early in this new policy, consumers haven't made big changes yet.

In this kind of situation, households will not respond until emergency public service announcements come out begging people to turn off their lights. Industrial demand will be the first area that responds and there will be many political problems. If this scenario comes to pass it's going to be bad for forward prices.

The industry will probably need a safety valve and an emissions pathway that pegs the price. This will provide pretty confident price visibility for the next 20 or 30 years.

One of the nice pieces of news is that in terms of criteria pollutants, prices drop almost to zero under a carbon policy. All the old units that are not scrubbed will be retired.

We have been hearing that technologies which reduce carbon or sequester carbon are not economic. That is only true when CO2 doesn't have a price. CO2 trading will make these technologies useful and economic.

So what should utilities do? If the industry has to make decisions now about what kind of plant to build, the standard response is to postpone a little bit until there is more information. Investors will look to buy delay options for base load investments. They will invest in capacity because capacity markets are much more violent than energy markets. In the Midwest in the late '90s power prices were in excess of $10,000 a megawatt hour for a while. Some companies paid a high price for not having good risk management systems in place at the time. One strategy could include going halfway by building some CCS candidate plants without the hardware. Finally, utilities should go forward with energy efficiency investment; push energy efficiency hard in exchange for some good will.

Speaker 3.

I'm going to talk about policy analysis of climate bills and their effect on the economy. I'm also going to discuss how companies handle risks and manage compliance with regulatory certainty, and more likely, regulatory uncertainty. How should investment decisions be thought about by companies?

There is a wide range of proposals in front of Congress right now. Investments that look good under one of these policy proposals may look like real dogs under another particular policy proposal. This increases the difficulty of investment decisions that companies are facing. There are a range of decisions. What kinds of plants should a company be building or acquiring in the case of an expansion? What should the investments be on existing units? There are a lot of retrofits for control technologies coming forward that are going to be needed in the next few years. Are those retrofits good investments? What kind of business does a company want to be? Is it better to be on the deregulated or regulated side? Many of these choices have to be made before there is resolution on climate policy choices.

The cap and trade proposals, over nine of them so far, have an enormously wide range of uncertainty. The price estimates for 2015 range from $5 a ton to well over $35 a ton, depending on which policy gets implemented.

Current coal consumption is just over a billion short tons a year in the U.S. Proposals that give us 2020 CO2 prices that are less than about $10 to $15 will still allow for very modest increases in coal consumption to around 1.2 or 1.3 billion tons. The Jeffords and amended McCain Lieberman bills give us prices in the mid thirties for CO2 and reduce coal consumption by about 20-25% to around 800 million tons. The original McCain Lieberman bill would give us $50 CO2 prices and put coal consumption at around 500 million tons.

The higher prices suggest that we will see no new coal investment without CCS. Further, existing coal generation is at risk of being

mothballed, and even implementing environmental retrofits on coal plants may not be worth the investment.

At $15 or lower, some new coal fired generation may be economical to invest in right now. That opportunity falls off very rapidly after the first few years because the "slow stop and reverse" associated with that price level means that coal plants will stop getting built and other renewables or low carbon technologies will come in.

At low price ranges, existing coal plants can remain viable; with a more orderly phase out. Some will retire early, and simply abandon retrofitting but it nevertheless allows a more systematic transition and a more stable fuel market. Of course, these prices don't reduce the emissions. In these scenarios the emissions paths are reducing but not reversing, yet.

Clearly, CO2 prices really affect the marketplace. However, they are integrated with many other drivers in investment decisions. What are gas prices going to do, what's the price of electricity going to do? The thing that really complicates this is the CO2 price drives projections for all of these other inputs to the planning process. Planning has to integrate a CO2 price and its impact through all the other inputs.

For instance, modeling shows that electricity prices increase slightly at low carbon prices, say around $10. This is about a 10% increase. Electricity prices jump significantly at the $30-40 range, around a 40% increase.

These numbers will significantly change the entire market environment. It's important to a business prospect if you own an existing plant whether it will still dispatch in that world. Similarly, load growth falls off only a little bit with a low carbon price. There is some energy efficiency response that can occur. It falls off very dramatically when driven by higher carbon prices. Natural gas prices at low carbon prices are affected little, but significantly increase at higher carbon prices. The main point is all of these things can move in different directions.

With very high carbon prices it is possible to see that gas demand starts to fall because demand destruction occurs across the economy. Gas prices are driven by economy-wide demand, not by electric sector demand per se. The electric sector demand for gas may double, triple, and yet there can be reduction in total gas demand across the economy. Gas prices are going to come down, somewhat counter-intuitively. These kinds of projection scenarios require integrated tools and a mutually and internally consistent set of assumptions in order to do the planning.

This kind of planning should address fuel markets, natural gas markets, oil markets, the transportation sector, and be integrated with a detailed bottom up engineering-based model of the electricity markets in the U.S.. It should incorporate macroeconomics and consumer welfare impacts. It can help one understand the dispatch of units, address new technologies, and implement the impacts of an economy-wide cap and trade program. One can use this kind of modeling tool for planning, but also to understand how different possible policies might affect the drivers in a planning process.

Businesses need scenario analysis that integrate uncertainty of policy implementation at the federal level. Scenario analysis is not enough, it needs to combined with the integrated modeling I've just been describing.

Further, this all needs to be integrated with probabilistic decision analysis. Consider a range of widely different carbon policy scenarios – say seven or eight, and a consideration plentiful or tight gas supply. In three of the scenarios, a company's decision to build coal or gas is dependent on the gas supply scenario. At that point companies need to probabilistically determine which scenarios are most likely.

Scenario analysis, integrated modeling and probabilistic analysis all need to be integrated with each other. Scenario analysis is helpful to highlight the riskiness of the decisions. Decision analysis tools are still needed to fill out the problem more effectively.

Decision analysis was popular in the early '80s, and it fell out of favor. Everybody started doing Monte Carlo analysis. Monte Carlo analysis is not the tool for this problem. While it is sophisticated, it is not good at addressing highly integrated scenarios that involve complicated models. Planners need to go back to basics and begin developing a probability tree. Each branch on a probability tree, which has many different uncertainties in it, defines a scenario. For each scenario, an integrated forecast of the markets that drive the planning process is needed.

One final issue is the question of regulated and unregulated scenarios and how different they are. On the regulated side we may see some of the first movers on advanced technologies. This will depend on a commission's attitude towards providing some coverage of the cost or risk. It may be more likely that commissions are willing to take on this risk, particularly in low load growth areas.

Unregulated generators have more volatility, and may gain or lose depending on what the wholesale prices are and their specific mix of assets. They need to think more about diversification of their assets and less about advanced technology.

Finally, uncertainties in gas prices, construction costs, and technology also factor into all these decisions in both kinds of markets.

Question: Does this modeling take into account global dynamics? For instance the global price of natural gas, or its demand?

Speaker 3: Yes, these modeling frameworks can be embedded in an international trade model. It has terms of trade though it's not always fully turned on, depending on the kind of scenario being run. For instance, it can be useful to capture the international dynamic of oil prices.

Question: Do you have data on the split between U.S. CO2 production and China in the future?

Speaker 3: U.S. emissions are right now approximately the same level as Chinese emissions. Chinese emissions are rising more rapidly.

Question: Your graphs represented demand destruction scenarios. Does your modeling anticipate whether that's really demand destruction in the sense of businesses changing, or is it energy efficiency?

Speaker 3: It is both, and it is possible to tease out the differences. The models don't have a lot of engineering detail on energy efficiency technologies. Instead there are production functions that can trade off the amount of fuel needed or energy needed to produce a given amount of output with more investment in capital. This is similar to saying one is buying a more capital intensive piece of equipment in order to get energy efficiency. That's occurring. There is also data on the output from the sectors versus the shift between fuel and capital. This can be analyzed to determine the reduced economic activity.

Speaker 4.

I am going to discuss these issues from the perspective of a coal producer. Is the future of the coal industry at risk? Producers think greenhouse gas legislation will affect, but not destroy, our industry. They expect the coal industry to remain a viable and integral part of the energy equation. Coal plants presently produce about 50% of U.S. generation. The existing 316,000 megawatts of coal capacity is not going to be easily replaced. Coal plants are likely to remain competitive and demand is going to remain strong. Existing capacity is not going to be able to be replaced in any short-term timeframe. Greenhouse gas technology development and demonstration is critical for the industry to remain competitive in the long-term. Carbon capture and sequestration is going to have to be viable in the long-term. Given all this, what's the impact going to be on the U.S. economy?

In the short-term, there is going to be more dependence on foreign fuel supplies like LNG. There will be rising power costs in the short-

term as supply and demand become imbalanced and utilities delay investment decisions. That's going to be a problem. Long-term, there will be increased costs associated with technology to address carbon. This will increase overall energy costs and restrain growth.

DOE [Dept. of Energy] estimates 5% and 30% parasitic energy loss associated with CC&S. While demand for power increase, there is the potential for reductions in capacity as these technologies are implemented. DOE expects 30-100% increases in capital costs, depending on which technology is being adopted.

For IGCC [Integrated Gasification Combined Cycle], it's a 33% increase, for pulverized coal it's 87% and for NGCC [natural gas combined-cycle] it's a 100% increase associated with capital cost. Electricity costs are projected to increase 29%, 72% and 60% for each of those respective technologies. DOE hopes to reduce those increases for IGCC to 10% and 20% for pulverized coal by a variety of programs and policy.

For many coal producers, the vast majority of their coal market is in existing generation. The existing generation will be here for a long time; it will be steady. Existing generation will become more valuable amidst delayed investments and market uncertainty. Clean air and clear mercury requirements can expand opportunities in markets if companies have adopted the right technologies. Further, if they have diversified and hedged some ownership in gas, this can help immensely as well. The new plant delays will probably occur in both gas and coal. Both fuels will need CC&S as well.

Short-term, utilities will use existing resources and focus on conservation. Short-term gas fired plants can help too. They have lower capital costs, and shorter lead times. However they will be relatively insignificant from a standpoint of capital. They will be incremental investments, not large long-term investments. They will be subject to fuel security and price risk associated with gas.

Demand growth is going to lead to lower reserve margins, at least in the short-term. Renewable projects will continue but they are small scale. The interest in nuclear is going to increase, but nuclear has just as big a problem as coal, if not more, in terms of siting, permitting, security, and waste disposal issues. Mining companies are going to begin to emphasize brownfield versus greenfield expansion. Producers won't invest a large amount of capital until they know what the market looks like. They will grow via mergers and acquisitions, not new capacity.

With regard to risk assessment and mitigation, it is difficult to quantify the risks absent legislation. Coal must demonstrate that CO2 can be captured and safety stored. CC&S is their path forward. It is the logical path forward for the entire country because it does not crash the economy. Further it provides a certain degree of energy independence and security.

Coal producers need to resolve the carbon sequestration indemnification issue. Once you put it in the ground and who is responsible for it? The U.S. has about 2,100 large sources that produce 100 kilotons of CO2 a year with total annual emissions of about 3.8 gigatons of CO2 per year – that's just producers. There is about 3,800 gigatons of capacity within 330 U.S. and Canadian geologic sites. The majority of those are in deep saline formations, however there is also deep un-mineable coal seams, depleted gas fields, depleted oil fields. There is theoretically a thousand years of capacity in CC&S.

Coal producers need to improve research capabilities. There is only one coal company in the country with a research facility. Active areas include technologies to mitigate coalmine methane emissions, generation with carbon capture through novel generation technologies like PFBC [pressurized fluidized bed combustion] combined with Sargas capture of CO2 for sequestration, and CO2 sequestration in un-mineable coal seams.

Energy legislation must recognize that coal is the most abundant domestic fuel source that we have. From a security and economic standpoint it is critical. Coal plants, with adequate R&D

and a little bit of time, can be built with near zero emissions. Federal funding to support coal utilization technologies is needed. The folks who have been advocating a Manhattan project approach to the CO2 issue are right. This problem is at least as onerous as the ones we faced during World War II. Carbon capture indemnification is a piece of that too.

Question: What are the indemnification issues for CC&S these days. I know they exist a lot for nuclear plants.

Speaker 4: There are similar issues. If CO2 is being put in the ground for a long period of time, what could happen to that, could it be somehow released? Policymakers have got to get past the issue of who is responsible for it once it is down there and what happens if it gets released. It's supposed to be designed so that doesn't happen, but there is still risk out there that it could.

Question: What's the length of term of a long-term contract in the industry?

Speaker 4: Ten years is considered a long-term contract.

Question: Is the coal getting shipped by rail? Are customers also able to sign transportation contracts for that length of period as well?

Speaker 4: I don't know. Shipping is done primarily by rail and by barge.

Question: Is M&A [mergers and acquisition] activity a strategy for something other than growth?

Speaker 1: Companies can grow organically or by buying or merging with other companies. M&A is the best strategy in times of policy risk.

Question: One speaker discussed decision analysis and why Monte Carlo analysis doesn't work with complex interactive scenarios. This means that hedging strategies, which include delay, are optimal *ex ante* and suboptimal *ex post*. Unfortunately we have to make decisions in the *ex ante* world. Several speakers argue the "slow stop and reverse" trajectory is best but nobody is proposing such trajectories in the legislation.

How far off are we from the optimal trajectory right now? The right move would be to do nothing for a while until you get your act together, and then start slowing things down, and then gradually start stopping and then accelerate afterwards? In the real world, that seems to be exactly what we're doing.

Speaker: The optimal path that comes out of the policy world may be different from target trajectories on a piece of paper. First, we could have a bill that is aggressive; flatten and then reduce. However, once the regulatory regime is actually implemented it could function as a "slow stop and reverse." This could happen simply because regulatory processes are inherently slow and adaptive. It also could occur because of alternative processes within the regulations. One idea is an alternative to the safety valve in which allowances at a safety valve price from a future year, say 2035, could be reallocated to the current year. Doing this would change a flatten and reduce model to one that is far less aggressive. It would turn the steady downward slide on charts to a "slow stop and reverse line." There are ways to make the legislation adaptive and still allow policymakers to say we're taking immediate action right now.

The second adjustment is the concept of banking. If the cap is right, even though the path is downward sloping, and the industry is low on the supply curve, people will harvest a whole bunch of the low-hanging fruit and save it for later, and then they will dump it in the market. The physical reductions will be slower or backward weighted. There will be early reductions that are physical, and subsequent ones that aren't but are banked. The effective path would look more like slow stop and reverse.

There are still going to be players who are willing to make deals and find good bets. Nuclear is maybe the best one. Nuclear is a good deal right now if one can manage the risks. Companies are not factoring carbon into their decision to build nuclear. The decision was

made before carbon on its own merits. It's got good economics if equipment costs and performance is under control. It's an even better deal if there's carbon and it happens to be a good way of solving the problem.

Speaker 3: The industry is involuntarily doing slow stop and reverse right now. Political pressures are there in anticipation of what's likely to happen. Second, companies use business as usual paths in their modeling as a starting point for comparison against different policy assumptions. However, business as usual should not be viewed as an extensive probability in any business planning process. Businesses need to see what's coming down the path. In doing that, most will put themselves onto a slow stop and reverse at a minimum. It's really important not to plan around business as usual. It's a very low probability event looking to the future.

How does the industry get to a more realistic path, even if the policy proposal is a very tight cap but borrowing or inter temporal flexibility is allowed. There are political realities in this that make it difficult. Borrowing is not a politically accepted approach. The proposals that have allowed some borrowing do it with a lot of red tape and hand tying behind your back. They understand that one cannot have a tight cap and then expect it because limited borrowing simply allows a return to the slow stop and reverse path. Models are showing that in these proposals the caps get so tight later in time that banking pressures will play an important role because of how stringent the cap is later. Future cap severity has a way of working its way back to the early years.

Question: You're talking about firm level borrowing, right?

Speaker 3: I'm talking about being allowed to borrow against your future cap. If a company is putting in an overall cap, it's cumulative over a period of time, say through 2050. If there's unlimited banking and borrowing, they have flexibility to find the optimal path through the market mechanism. That could lead to "slow stop and reverse." If it is set real tight with limits on borrowing, the market cannot adjust to the optimal path. The market will function better policy-wise with a loose cap in the early years and let people bank against it. This will likely result in "slow stop and reverse." A tight cap with borrowing is going to be much more difficult for the market to react to.

Question: Does CC&S readiness simply require having a larger footprint for the site? Is there a lot of plumbing, for example, or other tradeoffs in the design? Or simply having a place to add equipment should it become necessary down the road?

Second, one of you used a couple of ICF [ICF consulting] scenarios. A lot of those assessments depend extensively on gas supply cost. The gas cost assumptions were incorporated back in the due diligence days of the merging power plants that then went bankrupt. People shouldn't make real decisions on those studies.

Speaker: It is the space issue, ensuring there is some decent geology nearby, and knowing that there will be some de-rates off the plant. The capacity of the operation and what that adds to the system needs to be accounted for. Future changes will require extensive capital because turbines will need to be replaced because of mass flow issues. It's not just putting a box in and some pipes that go to a compressor somewhere.

Question: Is it simply that one would need to replace the turbine when you do retrofit, or is there a difference in the design?

Speaker: I'm not sure. There is no turbine right now that can burn pure hydrogen streams. That has yet to be designed. GE reps say it's no problem.

Speaker: It depends on two pieces: the generator, or the process at the generator. First operators have capture the carbon and then have a place to put it. Most facilities will use a saline aquifer, but there might be places where the cap rock is thin and crumbly and other places where it's thick and robust. One needs the latter. EPA needs to make sure that everybody finds the

robust cap rock. Good regional and state level siting processes will be needed to ensure that. This won't necessarily be that hard. Industry has been storing gas underground at pressure for a long time. There has been 30 years of gas storage experience and ten documented leaks of any magnitude at all.

The generation side is pretty complicated if one is retrofitting an existing plant. The technology is evolving. There are a number of different processes that use heat. One has to get the heat out of the plant. That changes the steam cycle and the boiler turbine dynamics. Finding a process that has a minimal impact on that is going to be important for economics.

For IGCC, there is a component you plug in between the gasifier and the turbine that takes up the carbon. The cost of that, the thermal load inside the gasifier, these things are evolving fairly quickly. So, one can build an IGCC plant today that can take carbon dioxide out and pressurize it. One can drill a hole and put it in a saline aquifer, and sell it for EOR. One can do that but it's hard to make it pay right now. It can't be done yet at full scale with back-end control or oxy-combustion technology.

Speaker 2: Some of your question is about readiness. Advocates out there are saying do it now, it's ready. It's not. One can't buy a turbine off the shelf yet, for one thing. There are a lot of political and regulatory issues to be resolved on CO2 injection. Utilities or generators are not happy about taking a big technology risk, neither are regulators. Deployment is going to take a wild. One company in Indiana has received one of the DOE grants for an IGCC plant. It is expected to be a phase three DOE test site with some large capture and sequestration. They argue it is creating a public good for the country and that Indiana rate payers should not be paying for.

Question: When it comes to actual sequestration, it will be in the gigatons and for many, many years. Is there strong science on the potential environmental impacts? For instance, years ago sanitary engineers thought dilution was the solution for their industry. This was well-intentioned but it was a disaster later on. What if Mother Nature burps in 2099? Are we creating the new Super Fund sites? What is the science for 50-100 year aquifer impacts, what are the risks?

Speaker: companies that are implementing projects right now have to consider this question quite a bit. These questions come up in Congress and in discussions in Washington. There is no question that the right places can store pressurized CO2 underground and keep it there indefinitely with minimal risk. And there are lots of places like that. There are places with saline aquifers, or other stored formations and firm, solid extensive cap rock that goes in all the various directions. There is extensive experience in storing other underground liquids that serves as the template for doing this.

There's also research and computer modeling, seismology; the same stuff that oil companies do all the time. Oil companies can monitor if a plume runs into an unidentified, uncapped test well from the 1930s. They can monitor and plug it. The science is very good that this will work. There is a wide variety of research and current and past on-the-ground experience with these kinds of storage systems in other contexts. The biggest concern is site characterization and finding the sites that have it. It also requires ensuring that CC&S doesn't occur in sites that are not suitable. That is the biggest concern.

Speaker: I agree. The petroleum industry's history shows the technologies for characterization of geology are very well known. They know what CO2 looks like in those kinds of formation, and how it acts. It reacts similarly , as a gas or a liquid, to previous experience in the petroleum industry. Industry people are pretty confident of a relatively low risk. The big job is the tremendous geologic exploration effort that has to happen. It's not cheap.

Speaker: Academic geologists who have academic reputations to watch out for are very careful to qualify their statements. If you talk to a commercial geologist in the oil industry, they laugh. They say of course it will work. This technology involves injecting a mile to two

miles down. That's a lot of rock and earth between us and the CO2. Further, it solidifies after a few years. It goes down in a liquid form and transforms into a solid.

Question: How many years?

Speaker: I don't know the exact time line. I think it's a hundred years, we're not talking about two million years or anything like that.

Speaker 3: The risks are three-fold. One is "burps", like the CO2. That's not the big concern, even though it makes a good story. Second is water quality. It makes the water acid and leaches out more of the heavy metals rather than having Perrier come from the tap.

The third concern is if the escape rate is 1% or 5% per year? We shouldn't worry about this as much as one might think because in many ways the next 100 years is a transition that allows continued fossil fuel use without continuing to load it into the atmosphere. Even if the leak rate is 5% that's still better than putting it up at 100%. It buys an important delay to transition from fossil fuels altogether to a low carbon source of energy. It creates atmospheric stabilization.

Question: One speaker said that the power sector is considered the most likely source of seeing some reductions. That's true for many reasons, not all of them economic. Many of those early reductions might include conservation and reduced consumption. Is there research that examines these issues at different CO2 prices. If they're not price driven, what drives conservation behavior, and how big it might be?

Speaker: I've heard numbers from non-economic sources that talk about 40% reduction possibilities. That may be over-optimistic, but it's a real deviation from the business as usual path.

Speaker: Economists think about this in terms to response to price, which is clearly important. Response to price can be both short and long term. Further there's response to innovation that is driven by profit opportunities, not necessarily cost avoidance. While conservation is laudable, we need to focus on transformative technologies that could make a big contribution.

With cars gas goes up by 25 cents a gallon but doesn't really stop anybody from driving an SUV. However, if somebody could make a better product that cost less, that ran on electricity and got charged up at night from low carbon resources it would have a huge impact. This is building and innovating a new product that satisfies consumer demand better. We didn't get out of the Stone Age because we ran out of rocks. [Laughter]

Speaker 3: Energy efficiency response tends to be larger when people expect the price increase to be permanent rather than a blip such as 25 cents in gas. Consumers don't know if 3-5 years from now they will be back down 25 cents. Carbon policy is permanent, and rising over time, in whatever price signal it turns out to be. Hopefully those policies will provide consistency for consumers to respond to.

Certainly estimates suggest a lot of energy efficiency improvement could be had "for free." However, even business as usual forecasts include a very large reduction in energy intensity in global economies. Electricity per GDP has risen since 1920. It rose from 0.2 to about 0.4, doubled through the '70s, and then started to fall. Current models show it has fallen back to about 0.3. By 2030 it will be close to the 1920 levels. However, the GDP will be much higher. Efficiency is expected to increase; less electricity to produce more output.

The question is how much more can one expect with carbon policy? It's above and beyond a substantial downward trend already. There can be additional reductions, it's a stretch but not infeasible. Breakthroughs in technology that one cannot anticipate are a big factor.

Question: Some of the debate for CC&S in the legislation sets expectations for when and how much reductions achieve, and that depends on technology development and availability. The last time the country had major environmental legislation, the technology was available at that

time to deal with it. Now the country is talking about developing technology in the future and setting goals on future expectations. There is a lot of variation in those estimates. Is there consensus as to when we will have CC&S technology available?

Speaker: This is like the question of when will the electric car be available? You can go buy one right now, the Tesla thing, and they are great. They are very expensive. They're ready but they're not in widespread use. Projects using IGCC with saline aquifer are in the development phase and expected to be operational in 2014. However, that won't be the technology of choice for base load power in 2015. These early projects rely on extensive public-private partnerships with states. Companies need extra support to make these happen. The technology pieces are already there, similar to flue gas desulfurization equipment in 1989 or 1990 during the Clear Air Act debates. Those are commercially available now.

Question: Should the predictions drive expectations for reductions?

Speaker: This depends on what the policy environment is. The right policy environment will accelerate the path. By the early '20s both the generation and geological aspects could be ready for widespread adoption and deployment on. Planning for 2015 to 2018 is an aggressive view.

Speaker: The industry needs 3-5 of these things operational with 5-10 years of data to determine commercial viability. It's going to take public money because rate payers should not pay the early experimental costs. Some industry folks say we can start right now if people said we'll help pay for it and if the industry screws up they won't sue you. [Laughter] That's unlikely.

Speaker: The technology is there, at least on scaled test facility levels. One concern is scaling this stuff up so it handles high volumes properly. Things work a lot better in a little teeny box than they do a great big box. The science is there. Engineering will take five to ten years, particularly to make it more efficient.

Speaker 3: Scaling up is critical. The industry will need innovation, a demonstration effort, a carbon price, and accompanying policy to make it happen by the 2020s.

Another issue is that if there are no constraints, CC&S replaces all other kinds of generation, with the exception of nuclear power. There probably need to be limits on each of those to maintain generation diversity.

Caps that involve 50-60% reductions are an immense transformation. For every ton of coal that goes into a power plant you get two tons of CO2 back out that has to go underground. If the entire U.S. electric system is run off coal then limits on the system have to be examined; how much total CC&S can actually be implemented countrywide?

Speaker: Some analysis shows a need for more than 30 CCS-ready plants per year, beginning around 2025 through 2060. It takes at least five years to build a plant. This means 150 plants under construction continuously for 30-40 years. That's a heck of a demand on commodity and labor. It will be very interesting.

Speaker: A great source of good jobs for American workers. [Laughter]

Speaker: And American lawyers.

Question: The EU has instituted carbon markets and has them up and running. They're now more stringent than they were to begin with. They got the initial allocations and the baseline wrong. They inadvertently created a "slow stop and reverse" function that is now more stringent. How do the U.S. and the EU compare?

Speaker: The U.S. has a strong federal system. The EU doesn't. We have companies lobbying for allocations. They have sovereign governments lobbying for allocations. They didn't have a well designed emission registry. We do. The U.S. can do a lot better more easily.

Speaker 3: The U.S. can get better coverage of the emissions. Their cap covers less than 50% of the emissions. Their other emissions are

continuing to expand. A good cap across the whole economy is needed. The best way is an upstream cap and trade around the fuels.

Question: I congratulate the folks taking a lead to push the nuclear option. It's an answer with good working technology and it can deliver. I am not optimistic about overcoming environmental opposition to plants – they haven't been in action because there was no activity to respond to.

Importantly, leadership is needed. Consider what caused the paradigm shift to carbon, carbon, carbon. There are still problems with the rest of our infrastructure falling down. The $200-500 billion that the country is planning on spending on CCS should be considered carefully. Our good friends in China are not signed up for CO2 policies. They're emitting as much as we are, 25% of the world's total and growing at a tremendous pace.

Until they are involved, this will put a huge burden on the U.S. economy. It will affect both energy independence and competition between the U.S. and China. Right now they have the third largest economy in the world and they are playing nice. In 10-15 years they will have the largest economy. They will not play nice at that point. The U.S. is hamstringing itself in dealing with issues that should not be on the top list.

We've needed a national energy policy for 35-40 years. We still don't have one. The gas lines in the '70s didn't produce an energy policy, global warming won't either. We could have a train wreck when every large U.S. coal project in the planning and permitting stage is under attack by multiple environmental groups and they're being delayed. Combine that with growing pressure on the supply and transmission system, and we will repeat the '70s; prices go up and reliability goes down. There'll be a bunch of expensive combustion turbines put up quickly and regret the policy path we're on now.

Speaker 1: The U.S. has to succeed in making climate change an economically attractive proposition for the developing world. China says it's a developing country; their story and they're sticking to it. There are two ways to do that. One is through diplomacy and appealing to the better interests of China. They have an enormous population that lives within 20 feet of sea level. They know it. They're not in denial.

Second, this is a massive capital investment. China just set up a sovereign capital fund of $200 billion. One could say the U.S. is going to spend a lot of money on this or that we're going to invest a lot. Where will the capital go to and what's the returns on capital? Is the technology cost-efficient and reliable? That's why nuclear is so attractive. That's why CC&S works for liberals and is also the choice of business leaders because it makes money.

It's not politically popular to think about $200 billion of Chinese capital flowing into the U.S. power sector but we need it, and a way to make a return on it. They need a way to keep the Yellow River flood plains from going under salt water. One of the basic principles of good government and infrastructure investment is to create good public policy and inject market forces. This creates rationalization, cost minimization, and value creation. This works for the infrastructure of the power sector and the whole country.

Question: Technology is the answer to staying in the game for the U.S. Staying on the cutting edge of new, efficient, and effective technology. Extensive Chinese investment in the U.S. gives them control and influence and that's a concern. I am concerned about their behavior when they are dominant.

Session Two.
Retail Procurement: In Search of No Fault Default Service.

When retail rate freezes come to an end and prices change, many things happen at once. New market conditions and new procurement methods apply, making it difficult to separate the relative impacts of

each. Politics enters with immediate demands for a change, almost any change. Power authorities, negotiated procurements, auction designs are all up in the air. Bathed in bad market conditions even a good procurement baby could be thrown out with the bathwater. This is a common dilemma that extends across all states. Those states with retail access still need a default procurement mechanism. Those retaining supply monopolies still need to buy or build, and may seek to employ competition in the process.

What have we learned about the design of procurement mechanisms? What new (old) procurement alternatives are being considered? How have the new auction methods worked, and what have they provided? How does the context in or out of organized wholesale markets affect the design choices? How, if at all, do procurement considerations differ in retail competition environments than in monopoly supply markets? How should competitive procurement deal with public policy considerations regarding resource mix and diversity, as well as public interest externalities? In monopoly settings, will competition among sellers provide sufficient protection for consumers, or should there be a single buyer with fiduciary prudence responsibilities for captive customers? What is the right balance of markets and regulation?

Moderator.

Today we will focus on how states in restructured markets procure power for the POLR [provider of last resort] obligations through utilities? This is pertinent because of some states removing price caps and addressing procurement of sources for mass market customers.

And what is the situation in traditional monopoly markets? What are the characteristics of a good auction? How do states deal with pressures to deal with supply portfolios, such as RPS [renewable portfolio standard]?

Let me discuss Colorado. They are a traditionally organized state. The fuel mix is about 70% coal, 25% natural gas, and renewables and hydro split the other 5%. Between 2007 and 2025, energy demand is projected to grow by 60%. They have challenges in greenhouse gas issues and overall growth.

Colorado passed an RPS this year doubling percentages from three years ago. It was the first state where a citizen-initiated ballot measure told utilities how much renewable energy should be in their portfolio. It passed by 59 out of 65 votes – there's a real consensus in the state. This RPS is 20% by 2020; the munis and the REAs are only 10% in that same timeframe. 4% of the 20% must be solar, and half must be on-site solar. There's a multiplier for instate resources.

Colorado has good wind. And, unsurprisingly, it's where the transmission lines are not. [Laughter] Those areas are really asking to have transmission built – how rarely does that happen? There are gigawatts of wind available. Clearly Colorado is far from a competitive transmission market that is agnostic with respect to fuel sources. There is extensive solar potential as well, including 100 megawatt concentrating solar that has storage so it's dispatchable.

They have a utility resource plan that must be filed every four years with a ten-year look ahead. It relies primarily on competitive bidding. It's designed to accommodate the RPS. It's "least cost within imposed constraints." Imposed constraints would be things like the RPS. It allows regulators to select a level of what are called Section 123 resources which consider issues like economic development or environmental quality.

The Commission undertakes a post-bid review of projects and decides which to pick out of the stack. The projects arrive in a stack ranked on cost, but some can be prioritized for these section 123 attributes. It's a moderate diversion from a strictly least cost scenario.

This sort of resource planning has regulatory overhead, but still relies largely on competitive markets. There are two phases. First, the Commission issues an order setting assumptions about load growth, gas prices, that can be incorporated into cost models. The Commission then produces a preferred scenario along with three alternative scenarios that are low, middle and high cases for Section 123 resources. Another example of a Section 123 resource will be an IGCC plant, or large solar projects. Those are obviously more expensive than base load gas or coal plants. This gives everyone a sense of how one state addresses these issues – let's hear from the speakers.

Speaker 1.

I'm going to discuss the interplay between environmental policy and retail procurement. This year has brought new legislative and regulatory challenges for all states, both restructured and regulated. These affect resource evaluation processes, resource decisions, and the futures of utilities.

The two most challenging issues are the RPS and mandated CO2 emission reductions – at either state or federal levels. Initial discussions have unfortunately led some policymakers and activists to call for a moratorium on new coal plants and the retirement of existing ones, along with a dogmatic focus on renewables and energy efficiency as the primary sources for new power supply. It's not just restructured states that are undergoing political upheaval and second-guessing.

I've reached the conclusion that there's little competitive market or even a self-directed future for any retail electricity provider in this country regardless of state or regulatory framework. The new unilateral focus on environmental issues pays no attention to the laws of physics in the electric grid or the laws of economics in terms of choice in fuel type. The passage of specific government mandated generation portfolio standards and penalties on the consumption of specific fuels will lead to reliability problems in all states, a deviation from least cost purchasing standards in traditional states, and a reduction in market-drive resource decisions in restructured states.

I'll discuss regulated states, then competitive states, and finish with thoughts on procurement. Most regulated LSEs [load serving entity] are making plans to meet capacity shortfalls that will occur in 1-7 years. New base load power can only come from three sources: nuclear, coal or natural gas. New nuclear plants, whether they be self-build plants owned by IOUs, consortiums, or wholesale plants built with equity partners or long-term PPAs, will take conservatively at least 12 years or longer. New coal plants are under increasing and hostile fire from environmental and NIMBY interests. They are challenging for approval, and many are being cancelled. This will lead to capacity shortfalls and possible reliability concerns. Since over 90% of new generation in the last decade was gas fired, there is significantly more demand for natural gas than domestic supply. We have higher and more volatile prices for natural gas, and more reliance on LNG. LNG will not solve the energy independence problem and decreases energy source diversity.

State regulators and LSEs are concerned with reliability, fuel diversity, and cost. The single-minded path of coal is bad, and only renewables, gas and energy efficiency are good, until new nuclear plants come online in 12 years is a problem. It changes the paradigm of retail policy principles in this nation. Consumers and policymakers don't understand this will be the inevitable outcome. It's the same as the unintended consequences of deregulating electric generation.

In retail competition states, we have not seen the intended results of more competition and lower electric costs for consumers. Perhaps the experiment would have worked under different circumstances, market designs, or a different lifecycle. That is irrelevant now. The retail prices in restructured states are higher than regulated states and will remain so unless fundamental changes are made to the retail service obligation, the procurement methods, or the wholesale market pricing structure, or all of

the above. The question only becomes what model do you move to?

Each state will continue to chart its own course based on politics, generation preferences, demographics, and economic development circumstances. Virginia and Montana have re-regulated, as best I can tell. Illinois will likely use a public power purchasing or construction power authority. Governor Strickland's proposal for Ohio will allow utility self-builds, rate recovery and cost of service pricing, along with competitive procurement. Michigan, Maryland and Maine are looking at re-regulation. There some groups considering re-regulation in Texas, although maybe not seriously. Connecticut is allowing utilities to build peaking plants and rolling them into right base. That adds up to nine states that are rolling back in some shape or form. That leaves only 8 other restructured states.

Many of these states also have RPS and CO2 emission reduction mandates. The question of developing base load generation is the same as the traditionally regulated states. This convergence of dynamics is going to accelerate the move back to a regulated regime. All the restructured states need reliability, so someone has got to have the obligation to serve. Cost controls are needed to minimize volatility and to ensure reasonable and predictable prices based on real costs.

The market will likely only build what is cheapest and easiest to build. That doesn't mean new nuclear or coal assets as true merchant plants. Wholesale nuclear and coal plants, like LS Energy and Dynegy are doing, will be helpful as part of the future. Projects like this need equity partners, long-term PPAs, or life-of-unit contracts. Short-term options in day-ahead and real-time markets will not produce these base load investments. Where do we go from here?

In either traditional regulation or restructuring, the various components of electricity service such as base load, intermediate and peaking supply need to be thought of as separate services in order to keep the lights on. The characteristics of each type of electric service are different, the fuel options are different, and so the construction, purchase, bidding, pricing and other procurement features should be conceived of distinctly.

We also need a tremendous amount of national and state-by-state education for policymakers and consumers on how electricity is generated, how it's dispatched, what kind of fuels provide the utilities load curve, and the need for different policies in each.

On average, 60% of a utility's needs are base load. Intermediate or load falling capacity is 30% and peaking is about 10% of the load curve, quite minimal. Renewable runs when it runs; intermittent in nature. It's primarily energy and not capacity, although that will change over time. Each of these types has different capacity requirements and fuel supply needs. Correspondingly, different policies should apply to each. When regulators look at diversified utility portfolio obligations for the utility, they should incorporate load curve specific RFPs and commitments so that resource choices are based on physics and costs, not just politics.

There is no focus on what fuel sources are needed to keep the lights on and the lowest cost option among alternatives. The choice is derived from what is environmentally benign and politically palatable. This will drive statutory mandates on what's allowed into generation portfolios. Investment decisions are based more on politics than cost or reliability. Congress has to balance cost and reliability against environmental concerns.

Nuclear needs to be resolved including getting Yucca Mountain approved as a permanent repository. Federal load guarantees are needed to build plants. A lot of money should be committed to R&D on CC&S. More drilling for natural gas in the U.S., not import dependence. Retail procurement strategy in the future needs to be about education, explaining to consumers and legislators what it takes to keep the lights on.

Speaker 2.

I'll be discussing the situation in New Jersey. In 1999 New Jersey went through restructuring in the Electric Discount and Energy Competition Act. EDECA made electric generation a competitive service. Two utilities sold their generation to unaffiliated companies and a third transferred it to an affiliate. EDECA also provided for retail choice, which was deployed a few months after the law was signed in February of '99. It created an obligation for utilities to provide basic generation service [BGS] for customers who didn't shop, despite retail choice.

EDECA required the utilities to procure BGS supply at prices consistent with market conditions. The utilities would pass charges for BGS onto their customers based on reasonable and prudent costs. This included cost of power in a competitive wholesale marketplace.

EDECA did not spell out the procurement method. It could be a number of things. The legislature that passed EDECA has no vested interest in the current BGS auction procurement process. The auction was created by an order of the New Jersey Board of Public Utilities in late 2001. BGS supply is procured through a descending clock auction for each of the four electric utilities.

The auction is split into two categories. A fixed price category is set at under 1000 kilowatts. That cut-off has constantly declined. At first it excluded only the largest commercial and industrial [C&I] customers, and then it ratcheted down. It was down to 1250 kilowatts and now 1000. This has a three-year procurement using a ladder mechanism. Every year there is a procurement that provides supply over three years, and results in a three-year average of prices yielded through the auction.

There is also a C&I energy pricing portion of the auction which is 1000 KW and above. This provides hourly pricing to customers above that threshold and is a 12 month procurement.

For customers below 1000 KW nobody is shopping. For 1000 and above customers there is a lot of shopping. Two-thirds of the customers and 85% of that load is shopping. I'll focus on the fixed price auction because the interesting state mandated stuff is happening there.

The first year of the auction the price was about $5.11 per kilowatt hour. After Katrina, gas prices start to go through the roof and there was an increase of more than 50% over 2005. With the three-year ladder, the effect of that is smoothed out quite a bit. The three year blend in the auction meant that customers did not see a 57% increase in one year. This was lucky, it was also good judgment.

They were lucky because the rate caps in New Jersey came off in 2003, much better than 2005 or 2006. The good judgment is derived from the three-year ladder so that price volatility is smoothed out for the fixed price customers.

New Jersey's BPU [Bureau of Public Utilities] is still trying to learn from previous experiences and every year the four distribution companies are asked to file comments on how the BGS supply should be procured in the coming year. There are also public hearings and stakeholder input. The proposals range from little tweaks to complete revamps of the system. Tweaks may be something simple. For instance in the descending clock auction, once the auction clears so bids account for all requirements and no more, whether the BPU ticks down once more after that and sees what happens on the tie. That proposal keeps coming back from the consumer advocate. They also keep proposing a pay as bid process.

Retail suppliers keep suggesting methods to encourage shopping and expand what the competitive suppliers can sell. This includes expanding the customer class that sees a retail margin added to their BGS price; a little bump that will make shopping more attractive. A retail margin captures the kinds of costs a third-party supplier incurs that a distribution company does not. Retailers want to expand who's subject to the retail margin, in that hourly pricing to customers all the way down to 100 kilowatts. They want to put them on a 12-month term

instead of 3 years. Those proposals would certainly increase shopping.

There is always some concern about what's going on in the market that's underlying the BGS auction. Is it truly competitive? Thus, another proposal that keeps coming back is disclosure of the contracts that BGS suppliers are entering into so that the BPU can understand the competitive mechanisms. Generally, the BPU has been rejecting all of these proposals because they don't believe they will produce the desired result, or reduce prices.

However, the pressure gets stepped up more every year. At the BGS hearing about two weeks ago, the State Public Advocate pitched their proposal for a portfolio management approach in which the BGS auction would be some segment of an overall portfolio. There would be a portfolio agent shopping deals year round to take advantage of the best deals through timing, length of contract, long-term contracts, and some demand response. These ideas could be incorporated into the BGS procurement to advance other state goals. The BPU is running a working group on all of this.

Is there going to be a push to throw the baby out with the bathwater? One obvious issue is price. Prices are going up. It's not necessarily the BGS procurement process, which is tracking the market well. Anytime there is concern about prices there is a simultaneous concern about the competitiveness of the wholesale market. Currently there's litigation between New Jersey and other states and PJM that's currently before the FERC questioning the independence of the PJM market monitor.

The BPU has also requested the market monitor's input to review the BGS auction and the market underlying it. They want a better understanding of whether the auction can be improved in terms of competitiveness. Concerns about price and competitiveness create a lot of pressure.

Additionally, there are externalities to consider. In July, Governor Corzine signed the Global Warming Response Act. It has aggressive targets for greenhouse gas emissions in New Jersey for 2020 and 2050. These standards apply to non-state imported electricity as well. It's going to be hard to reduce those greenhouse gases and also deliver a better price in the BGS auction. Integrating this requirement into the auction will also be a challenge. One idea is an emissions portfolio standard to address environmental requirements on CO2 but also for mercury and other pollutants.

The previous speaker was saying that there will be a move back towards regulation because it's superior. New Jersey is not about to do that. It's unclear whether the market or the state government can deliver electricity at a reasonable price, with the right renewables and greenhouse gas profile. It's questionable whether government can take over from the market. There may not be the legislative will. Further, even if they do it, then regulators have to deliver cheaper prices with the right environmental attributes. No one wants to be left holding the bag after making an aggressive push to takeover from the market if the results are mediocre.

However, the worse they continue to do on price, even if it's derived from the wholesale market, the less confidence there is in the competitiveness of the wholesale market. The political pressures are going to continue on both price and environment issues.

Question: How many different suppliers have participated in the BGS? I know 17 won this year.

Speaker 3: It's over 20, but I don't know the exact number.

Speaker 3.

I will talk a bit about procurement both in structured and restructured states. I'll discuss general methods, New Jersey, and some other general issues. Let's consider what a utility procures and why. This could also be government agencies or regulators.

Utilities have to procure supply for default service, customers that choose not to go with an alternative retail supplier that remain on utility service. Although the utilities still provide distribution under cost-base regulation, there is a separate process to procure supply for default customers.

In regulated states, utilities design and manage a portfolio of resources for their customers through self-build or competitive bidding processes. However, restructured states are thinking about portfolios of resources somewhat. Thus portfolio resources are not the exclusive purview of non-restructured states. Further, there are competitive procurement processes in both restructured and regulated states.

In restructured states, the default product is full requirement service. This means that all the services are being procured, energy capacity, ancillary services, et cetera. Second, the complete bundle, or portfolio of services is procured at a fixed price. Third, the suppliers are supplying a percentage of the requirements of customers. The suppliers meet all the load variations and the risks associated with serving those customers.

The implications of this are that the risks are transferred to suppliers that are bidding and signing contracts with the utility. Compare this to managing a portfolio of resources. The function of putting a portfolio together is essentially put in the hands of suppliers. Full requirement resources like this are required in regulated states as well.

Let's discuss the innovative clock auction used in New Jersey. It is the first time it has been used for this kind of procurement. There is experience with this kind of auction method elsewhere, for instance in spectrum licenses. There are two features to the clock auction: it's multi-product, and, second, it's multi-round.

Multi-product means the load for each of the four utilities is being bid in a single process. The multi-round feature means there are prices for the utilities that are being suggested to suppliers. Suppliers are asked to bid how much they're willing to supply at the prices being suggested to them. If there is more supply than needed, then the price tips down. The process continues downward until there's just enough supply for the distribution companies. Since it's a multi-round process, bidders can switch their bids from one utility to another in response to the relative prices in this process.

The other two primary methods are sealed bid process's or RFPs – both legitimate ways to procure. The clock auction has two advantages. There is information provided to the suppliers in the multi-round process. This decreases uncertainty from the supplier's vantage and enables them to bid more aggressively in the auction. Second, the ability to handle a multi-product setup easily with bidders able to switch bids from one utility to another allows them to arbitrage price differences and provide relative price levels that are consistent with the market. This method is also used to procure standard product in Spain.

The multiple rounds provide information in terms of how the market is reacting to price levels, and how much excess supply there is. A supplier can determine the state of the market much more accurately. It allows them to vet out their supply and adjust prices to keep them in the market at the next price level. Practically speaking, the auction is done via internet bidding. Suppliers can conduct their analyses in their regular place of business.

The prices that come out of this have tracked gas prices very tightly. It's not a mathematical proof, but there is general consistency with the underlying wholesale market. It reflects regional and global market prices.

If one questions whether the market condition or the procurement method drives prices it seems very clear that the market conditions are clearly the causal mechanism. Obviously it's important to test the competitiveness of the markets but the data seems to show this kind of auction process is providing competitive prices in a wholesale market with rising prices. One would expect the BPU to look at these issues but at first glance these mechanisms seem to work properly.

It's better to be lucky than smart. In that case, coming off the rate freeze in 2003 was much better for New Jersey than if they had come out now. Even though rate freezes were part of restructuring arrangements and had their place in states that restructured at the time, they impeded the development of retail markets. Competitors could not arise because the rate freezes were set at below market levels.

Speaker 4.

Let's start first with the legacy of the intellectually dishonest sale of restructuring. Nobody in the political arena ever mentioned to the public that the real goal was to improve efficiency? The goal was sold as lower prices. Then, to make sure everybody bought into it, there were Christmas presents for all organized interests. California restructuring passed the legislature unanimously, everybody was happy. State after state had preponderant majorities. These legal bribes for interest groups included price freezes in many states. A few states like Pennsylvania started to realize that if we freeze rates and make default rates attractive, there will be no competitors. Massachusetts decided implemented a 17% rate decrease, a cost recovery deferral. They also expected competitors to appear during the period of that freeze. That's truly idiotic. If one is trying to promote competition then having a below-market default product is the absolutely wrong thing to do.

There was similar idiocy in Illinois. Consumers were asked to pay rising prices for the same assets they paid for already. They have a right to be very angry. That is exacerbated when there is a bid and the incumbent wins. There's certainly no reason to believe the Illinois auction was rigged but there is a question of perception.

The first speaker asserted that regulated states have lower prices than restructured state. That's true but it doesn't show anything. For obvious reasons, restructured states had higher costs to begin with.

Everybody on this panel has been talking about markets in competitive and monopoly contexts. My next point is inconsistent with the previous speaker. The monopoly market and the retail default service issue in a competitive market are completely different. In the retail monopoly market, retail supply should be attractive with low prices and demand side activity provided by the supplier. The objective is an attractive retail price, and adequate supply.

In competitive retail markets default service has a different function. The default product should be unattractive. People need incentives to shop and go away from the default product. Customers should be able to exercise intelligent choices. An attractive default product keeps them from doing that and destroys competition. These are fundamentally different objectives for each market type.

Let's consider certain characteristics in each context. Reliability is necessary in both products. Attractive price is only wanted in monopoly markets. An attractive default price does not promote competition. Price signals. The price signal in a competitive market is that if you want it, you can buy it, but it's not an affordable product. Alternately, in a monopoly market, price signals are important in a broader way. They should be low enough to protect consumers but not extremely low so that they still encourage consumption and discourage conservation.

What about judgments or decisions on supply? In a retail competitive market that responsibility falls on the customer. If they choose not to exercise it, they get the default product. The default product supplier should not be exercising judgments. It's no longer a default product if it implements supply decisions but rather has become a monopoly market. In a real monopoly market, the business judgment is made by the supplier, and they exercise business judgment and prudence responsibility.

What's the fiduciary obligation of the supplier to the customer? Well, in a competitive retail market, it's limited to reliability, keeping the lights on, nothing more. The fiduciary obligation

in a monopoly market is comprehensive. It's reliability. It's economic. It's all those things wrapped into one. The monopoly supplier has to exercise prudent judgment on behalf of the customer.

Supplier incentives in monopoly markets are both reliability and price. Both those incentives need to be adequately incentivized. There is a legitimate critique of monopoly markets that in terms of price there tend to be greater incentives to build rather than buy – this is fine for reliability but not for price. That needs to be addressed very carefully by regulators in monopoly markets.

The scope of the auction is the same in both cases. You can divide it into trenches as one speaker discussed earlier, although I don't think it helps that much in competitive markets.

Regulatory oversight is critical. In a monopoly market this is prudence review. There is a fiduciary obligation owed to the consumer and the regulator has to exercise it. In a competitive default product, the regulator is designing and putting in place an auction. They are overseeing both the structure and the process. The regulator is the supplier.

In situations with monopoly markets that is a problem; one shouldn't be both. It doesn't function very well. When one is designing different mechanisms at the regulatory level they are doing both competitive auction procurement design, and then doing prudence reviews down the line – that's not good.

If one wants to promote competition, you need a product that's not attractive. Regulators need to oversee that to make sure that's the case and stimulate competitive entry. Regulators should not be designing auctions or other procurement systems if they are also doing prudence reviews. It's not a fair division of that kind of management responsibility and regulatory responsibility.

Let's discuss timing of regulation. In a competitive market it's ex ante. The regulator determines the procurement mechanism for the default product ahead of time. The only ex post review is just to make sure that the rules were followed. In a monopoly market the emphasis is on *ex post* prudence reviews. You should have ex ante rules so people know what the rules are but they are less important.

Management judgment. In a competitive market, the management judgment in a default product ought to be limited because they're not competitors. It's only a default product. Management judgment in a monopoly market is essential. They need skilled, competent managers knowing the energy markets.

Demand side incentives for the default product are not needed in the competitive market. The idea is that competitors would offer an array of options for supply and demand side activities to serve the customers' needs. In a monopoly market, demand side has to be an important part to get an appropriate balance in a monopoly market.

Obviously, in a competitive market there should be demand side service. I'm only saying it's not the role of the default product.

Finally, in both kinds of markets the politicization potential is significant. An auction does not remove the politics. Illinois is a model for that. Where customer choice is an illusion, or where the incumbent wins having recovered stranded assets, the politicization potential is enormous. In a monopoly market, it's always a possibility.

Auction mechanisms. For default service, an auction mechanism meets the needs. In fact, the sophisticated models discussed by the previous speaker are arguably too sympathetic to consumers. Nonetheless, an auction mechanism meets the need in default service and removes the incentives for vertical integration and dispatch biases in non-RTO regions. That's useful because there's always controversy about whether the vertically integrated incumbent is skewing the dispatch order in its own favor.

Auction mechanisms in monopoly supply regimes can be useful. They remove incentives

for vertical integration to create a market for getting appropriate pricing and services to customers. It removes dispatch biases; there's a transparent mechanism when it's well administered and overseen.

However, it has certain problems. It puts regulators in charge of supply procurement which is a problem I've already discussed. It could strengthen the capacity market while reducing reliance on the energy market. That depends on auction design and competitor behavior but it does have that potential.

There are auctions around the world that are reflective of capacity, and not energy at all. That's risky especially when the auction mechanism may become rigid overtime. It limits nuanced supply management judgment. The importance here is in the auction design and enforcing the auction design. And it's very difficult when it looks like Defense Department procurement programs. There's room in energy purchasing for nuanced judgments that should not be eliminated. There are concerns for socialization of risk and rewards, although that's a constant in all electricity markets. Finally, the potentially higher transaction costs and overall power supply procurement are a concern. These include power purchasing, load balance, ancillary services, FTRs, heat rate indices. Trying to integrate all these into an auction can create increased transaction costs and complexity.

Ultimately, auction mechanisms make sense for default service in a retail choice model, but non-auction models are more sensible in a retail monopoly market.

Question: Are you speaking of "auction" as a single clearing price, single product auction as opposed to a competitive procurement? You're distinguishing between the two?

Speaker 4: No, but I would distinguish between the two in terms of the degree to which I would find them objectionable. My statement was broader than that and isn't as nuanced as my thinking actually is on it.

Question: When rates are going through the ceiling as a result of a competitive market, should the role of the regulator still be only that of monitoring structure and process?

Speaker 4: I'm talking about the role of the retail regulator. This has nothing to do with FERC. I am looking at this only from the retail market point of view.

Question: It seems that your underlying assumption is that the goal of a competitive market is an end state of competition in and of itself. Do you think that was the intent of deregulation? It seems the goal today is a competitive price for those consumers who really cannot switch. Your comments assume that the goal is competition itself.

Speaker 4: The objective is an efficient, reliable supply of electricity at reasonable prices. That's the objective. The question of competition in monopolies is a question of the methodology. My comments concern retail competition, not wholesale. If regulators or legislators believe retail competition is the best way to get there then a market design and default product is needed that doesn't discourage competition or serve as a barrier to entry.

Question: You had a comment about socialization of risks and rewards for auctions in monopoly systems; could you elaborate?

Speaker 4: In a monopoly market the suppliers interest should be perfectly aligned with the consumer's interest. It may or may not be, depending on how well you design the mechanisms. Those who design and administer the auction socialize all the risks and rewards onto the consumers.

Question: That's because a monopoly system takes risks and rewards from the supplier and passes them onto the customer. That's an advantage.

Speaker 4: That's what prudence is all about.

Question: I would like to connect this morning's and this afternoon's presentations. One of the

speakers demonstrated that auction results are roughly consistent with the wholesale market. Is the market producing prices that are close to underlying cost? How do these prices relate to underlying costs?

If these prices reflect marginal bids then isn't the marginal price or bid going to be going up for the foreseeable future? With increased worldwide demand and renewable requirements, is the industry in a semi-permanent state of the marginal price being higher than the average cost? If so, then consumers will be paying top dollar for coal or nuclear or hydro or whatever? I can't see that auction prices or market prices are going to come down or meet average system costs that the regulated system does produce. Isn't that why prices have been going up in deregulated states and regulated states have had a more stable level?

Why would one ever abstractly say we're committed to competition? Shouldn't regulators continue to test whether the system is bringing prices closer to underlying cost?

Speaker 4: It's not necessarily to drive prices down. Incentives need to be developed to drive down cost so people are more efficient. If the market is competitive that would bring down the prices. The critique of the old monopoly market was that regulators didn't develop the right incentives, and there was waste in the system that could have been run more efficiently. One could drive prices up to meet the cost, too. The real question is how to provide adequate incentives for really efficient performance? Is competition or monopoly the best way?

Speaker 2: Some advocates in New Jersey suggest that prices could be better than the BGS auction is delivering. On the one hand there's a wholesale spot market with a single clearing price, and there's also an average production cost that's lower than that. How does one capture that difference? It's probably not possible under any likely procurement method because once generation is a competitive service they can sell into the spot market if the procurement methods cut off too much profit. I don't think there's any way to drive the price below what the BGS auction obtains. Nothing will get you closer to the average production cost.

Question: Doesn't that mean that New Jerseyans are going to be paying higher prices than they need to for quite some time?

Speaker 2: I don't agree. No matter what the system is, the generators need to cover variable and fixed costs. They have to make a profit or it's not a sustainable business.

Question: I agree. The question is whether the competitive market is either producing more plants than needed or is paying all of them collectively more than fixed and running costs?

Speaker 2: That's a separate question. What is the competitiveness of the underlying wholesale market? If it's not competitive then there's always a concern for bad prices.

Question: Let's consider the competitive market as the means, not the objective. Default service addresses a special class of customers who won't go into the competitive market because of coach potato problems and the like. How does one solve this problem? It's a third class of customers. There is a fundamental portfolio management problem to be solved. There are four candidates of who should be the portfolio manager. The legislature, the regulator, the utility, or the participants in the marketplace; Morgan Stanley and the like.

There are two ways to characterize the portfolio. One is in terms of the outputs, full requirement service. The other is in terms of the inputs which is generating plants providing power at a location to meet load. Importantly, the more the portfolio goes towards the legislature and the more the system focuses on inputs, the more problems there will be. The degree of flexibility and available options are reduced the farther you go up. Market participants have the most flexibility. Legislators have the least because they must specify everything in legislation. And at some stage the outputs have to be determined and converted into inputs.

One of the good things about the BGS is that it puts default service in that third column. It's a competitive market that's attempting to do the right thing for consumers. They're not being forced into the competitive market. It's specified in full requirement service. The portfolio management problem is faced by the people who are bidding into that. They price it, of course. The fundamental question is whether the marketplace or utility management or legislators are better at addressing the portfolio management problem. It's important to clarify the difference between outputs and inputs. When one starts specifying inputs and transmission has to be implemented, they're in a quagmire. One of the great beauties of the BGS is that regulators or utility management don't have to specify that.

Speaker 3: It's important to ask who is best suited for the portfolio management function. It belongs in the hands of competitive entities. There are other wholesale market structures and policy levers that influence the portfolio selections of competitive entities such as renewable portfolio standards or compliance payments,

At the RTO level, the structure of capacity markets can have an influence on the inputs and the portfolio decisions that competitive entities make for their inputs. It's truly impossible to have a smart shopper that can time the market and lock in long-term stable, cheap deals.

Speaker 1: The big problem with emerging portfolio standards on a state and federal level is the disconnect between inputs and outputs. People don't understand that renewables and energy efficiency cannot produce nearly enough base load power. It ain't gonna happen. If utilities are constrained in their portfolio, there will be a reliability and a cost crisis. The market can't build merchant nuclear. They want long-term equity investors, and PPA purchasers whether it's a coal or a nuclear plant. The market will build gas and it may do renewables, but it's not going to do nuclear and coal. And that's what you need for base load primarily.

Obviously, you don't want consumers having that responsibility. They don't want to know where the power comes from. They need to understand it. They cannot control it. They just want to flip on the light switch and have the lights come on. Utilities who know how electricity is produced and know how to deliver it are best positioned to manage a portfolio in a least cost manner. Regulators can oversee that with IRP and competitive bidding rules, and prudence reviews. That's the best outcome.

Speaker 2: I have a different perspective than the previous speaker. The regulator has an important role to manage inputs. The market does a lousy job of planning on inputs. For instance, consider air pollution where the number of asthma and bronchitis cases, emergency room admissions from high levels of ozone are increasing. Power plants are a major contributor to that. Market participants don't pay for this, just the sick folk. They won't eliminate that problem voluntarily either. There's a similar problem with mercury emissions and wiping out regional fisheries. Again, market participants do not see costs and won't respond to them. It's the same with CO2.

With renewable inputs there is reliability of course but it's more than that. The renewables market needs to be transformed in preparation for a carbon constrained world. The market needs help here; the costs of these technologies have to come down. Renewable technologies will not provide base load power like a nuclear or coal plant, but they need to be part of the mix. These issues all need to be managed with regulatory and legislative oversight.

Speaker 4: Market participants do have the most flexibility. Legislatures have the least, that's also true. Auction mechanism design is difficult because it's hard to define market participants on the supplying and bidding side.

In a monopoly regime there could and should be an intermediary between the customer and the bidder that can develop incentives. These can address the externalities the previous speaker just discussed. Further, somebody has an incentive to be intelligent about it. If regulators design auctions they lose flexibility.

Question: The BGS process provides a competitive price to consumers who don't really want to shop. It has other potential benefits in terms of risk and decreasing politicization of the wholesale market.

If consumers were truly facing the spot market in that situation would the BGS process have survived? The hedging and price stabilization aspect seems important for reducing the political aspects of these markets. To what degree is the ideal competitive framework to increase customer exposure to real-time prices? Is the BGS unsuccessful because it's providing too competitive a price in a retail framework? However, the BGS provides benefits for consumers by addressing risk and hedging for the customers.

Speaker 4: That's a good point. To some extent, BGS is kind of a hybrid. The more one designs mechanisms to make the default product more attractive, the further one moves from a competitive model.

Question: Do we want people exposed to prices as they were in California?

Speaker 4: I think that's the question. The industry approached the question of competition dishonestly; they haven't faced that question head-on.

Speaker 3: I haven't met a regulator yet that's telling me that this is all fine, the price is high and we love it. [Laughter] In places like Pennsylvania, Illinois, and New Jersey, there's a concern in trying to set up a system that's fair to all competing suppliers and still get the most competitive price for default customers. The problem is pricing so that retail competition can develop.

For larger customers in New Jersey, real-time pricing is not bad. They simply may want to pay a consistent, non-variable price. For smaller customers in New Jersey, a price hedge for a three-year period where all risks are on the suppliers is a premium product to a large degree. The suppliers address changes in the regulatory context, in PJM, migration of customers on and off the service, and so on. That price reflects those things. One expects other retailers to compete against that. Competition for competition's sake is not the goal.

Question: Does everyone remember Bachman-Turner Overdrive's, *Baby, You Ain't Seen Nothing Yet*? Prices are going to go way up between the needs for transmission and generation investment, and the social policy goals that the market does not identify for us. Cost will go up astronomically.

The response in the regulated world is deferment. Not stabilization, not a cap. BGS prices will go up to meet these goals but at least this is addressing the costs head on. For regulators, what is the obligation to be honest with consumers that either they pay for it or their grandchildren pay for it?

Speaker 1: We all realize that the industry is facing very steep price increases. Perhaps 50% over five years and 100% over the next ten years in regulated markets. Regulators need to try to connect the dots better for consumers and legislators. They need to know that when environmental or developmental portfolio standards are put in place, there are big cost and potential reliability implications. Education is paramount.

Further, the model for procurement and/or self-build supply has to produce the best result within portfolio standards constraints. What's least cost and the most reliable? It will probably end up being a hybrid in most states of some competitive options and an IRP process, but self-build is going to have to be part of the option.

On wholesale, if Exxon is going to build a nuclear plant, they want equity ownership partners or long-term life of unit PPA purchasers. Everyone doing nuclear will want that and the same for coal. That's the only way those plants are going to get built. The model in retail procurement needs to reflect those realities. Let's educate the legislators.

Speaker 2: The word has to get out that infrastructure needs are so desperate that real costs will kick in to meet them. There's no free lunch procurement. If prices go up, it doesn't mean auctions or BGS are a failure; they simply reflect market realities.

The more prices go up, the more pressure will mount to look at other ways to procure supply. The more understanding there is that New Jersey is delivering the best they can out of the wholesale markets, the better they can sustain the best model, to my mind.

It's a good thing that for the fixed priced customers, BGS is attractive enough that there's no need for shopping around.

Speaker 4: Prices are extremely important. However, that was the wrong focus. This distorted the restructuring debate enormously. The focus should be how do we get the most efficient electric power sector possible? How do we keep costs as low as possible. Prices are going to rise because needs are rising. The right question was not asked in the restructuring debate.

The fundamental problem here is civics. Society is incapable of making decisions because we focus on what bribes we have to give different groups. Whether it's giving residential customers and rate freezes, utilities and stranded costs, social benefit funds, etc. It's wrong. The emphasis should be developing an efficient sector.

Speaker 3: It's not sufficient to simply say these things are going to cost money. It's better to frame the policy debate by asking how much are legislators or consumers willing to pay for it. This could apply in Illinois. What is the tolerance for rate increases, and how much are you willing to fund out of those rates? This limits inputs in a way that makes costs more obvious to consumers and legislators.

Question: What is the implied difference between auctions and competitive procurements? Second, what was some of the original thinking on how greenhouse gases will be addressed in the context of something like the BGS auction?

Speaker 4: Auction is simply a means of competitive procurement. Competitive procurement includes bilateral negotiations and other things.

Speaker 2: Fourteen months from now, CO2 emissions from power plants over 25 megawatts in a ten state region, that includes New Jersey, are going to be capped. There will be a cost adder on generation in the RGGI [regional greenhouse gas initiative] region via its trading mechanisms.

A concern for supply procurement is that imports from outside the RGGI region may increase because there is no carbon adder in those states. This would undermine the whole environmental benefit. New Jersey and the RGGI states are trying to explore ideas to keep that from happening. Put generation inside the region on an equal footing with generation outside the region with respect to CO2. In New Jersey, we may see the BPU establish an emissions portfolio standard to fight this leakage phenomenon as one way to do that. It's still in discussion.

Question: Will it end up being incorporated into the full requirement service product in the auction?

Speaker 2: Yes. The details are still being worked out.

Question: I have a question about favoring in-state resources. The Colorado RPS has a multiplier for Colorado resources. What does this look like? What is its legal viability given potential commerce clause challenges? What are the ideas about how to favor in-state resources for RPS or other purposes that will be resistant to a commerce clause challenge?

Moderator: Colorado's in-state multiplier is 125% for renewable energy resources. If you buy something that's 100 megawatts, you get to multiple it by 1.25. There are other multipliers that don't have that effect. There have been no

challenges on commerce clause grounds. Politically, the wind people in the region are unhappy about it, of course.

Renewable energy is seen as a huge growth industry in the state. The RPS is linked to economic development in the state, that's the view in the legislature. Jobs and property values. There is a powerful coalition between farmers and environmentalists. The farmers are looking forward to $4,000 a year rent on a wind tower on their property. That's much more than dry land wheat.

The in-state multiplier may become unnecessary because there's regional interest in doing transmission to ship power to Phoenix and LA. They are promising markets for the green power.

Speaker 2: There are two separate questions. Leakage and renewables. In terms of leakage, it's not favoring in-state over out-of-state generation. It's a matter of strict environmental requirements in New Jersey that other parts of the region are not subject to. It's simply a question of equal footing.

On the renewable side, there's a strong desire to have money in renewable development benefit New Jersey directly. There's a requirement that electricity from the renewable sources be deliverable into New Jersey.

There's not a straightforward way of favoring in-state resources. Basically the state can put its own money into the game and give monetary incentives to developers of in-state renewables.

Question: I have comments on some of these reactions. There is a need for nuances in procurement. California comes under the auction category but is not fully competitive on the retail side. There is retail access in California that involves a utility buying for their bundled customers and using an auction method within the utility context; a hybrid.

They're not just auctioning on price. It's a hundred different terms and conditions. There's a structured auction process with an independent evaluator and oversight, but there's a lot of room for utility management nuances. These are important.

It's not just about megawatts. It's about megabars, locations, intermittent renewables and their backups. This issue will get more complex as we layer on increasing renewable, GHG, and technology requirements. How to handle this complexity?

Second, how does it get financed? For utilities, what is view from credit rating agency's on these PPAs, their assessment of debt equivalence and the impact on utility balance sheets. Utilities cannot withstand the balance sheet impact of a 30 year PPA for a nuclear plant or IGCC that is clearly above market.

Speaker 1: You're right, these are very difficult problems. The market cannot work the way they are supposed to work.

State control is endemic to this problem. RPS and energy efficiency portfolio standards, carbon reduction mandates, moratoriums on coal, and restrictions on nuclear financing. There are many state level constraints. Getting generation built at an affordable price will require long-term partnerships between regulators, utilities and folks in the market. This will require commitments for the life of the unit in order for them to get built. That's what Wall Street is going to need. Clearly, these kinds of long-term PPAs are not market based.

Question: There is a premise that competitive supply precludes the required investment in coal and nuclear. If so, do the markets actually function? On the other hand while merchants will not build coal or nuclear, they will buy nuclear plants outright. They don't have commitments for the expected life of those plants today but they're buying and operating them.

A merchant entity won't build a nuclear plant even if its expected market value vastly exceeds its expected building costs. There's a big question mark on the building side. The last nuclear plant cost $9 billion, four times what it was expected to be.

Will the value of a nuclear plant ever sustain that type of investment? It might not be prudent for anybody to build it. Competitive supply could not build this type of plant – please comment.

Speaker 2: Purchases of existing plants in retail competition markets like Texas are very different from building a new plant. If purchasing, the entity gets headroom between the costs and selling at marginal costs. Texas' assets have flipped over three or four different times in this way. It can be done in an economic fashion. Building new plants is tougher and doesn't have that characteristic.

New nuclear and coal plants will only occur with long-term off-take contracts or equity ownership partners in the plant. Spreading that cost and making it long-term reduces the financial risk but only if there is a guarantee the cost recovery long-term can occur, in either kind of market.

Speaker: Part of the problem here comes from price projections. They have to socialize these risks to build this kind of plant either through long-term contracts or grants from the government. For new technology, that may be a legitimate argument.

If so, what's the appropriate symmetry? What do these plants give back in terms of rates of return if that risk is removed? Part of the reason I am an advocate of competition was because the equilibrium became completely distorted in the regulated world. The industry is too readily prepared to socialize those risks to get something done.

Question: One of the enabling pieces of the BGS auction is the wholesale pass-through to large C&I customers in the market. This is a fifth bucket, correct? Second, how does that fit into the goals of renewables. California is just beginning to address this problem and they are looking for solutions.

Speaker 3: I'm not sure I can link all the pieces together either. There are a lot of these customers shopping in the New Jersey context but I'm not sure what they're getting from the retail providers. Presumably this includes green products.

Speaker 2: New Jersey doesn't know what 85% of the load above 1000 kilowatts is getting when it's shopping. Nonetheless, these customers have great incentives and ability to manage their buying well, and I expect suppliers are getting to their needs. This works great in terms of the exposure to hourly pricing. I don't know if it's as useful on the green side of things because large users only tend to buy green for PR reasons.

Question: What is their ability to get off the system? We always consider the supply side of the equation. How many green things are we going to build? Alternately, how many brown plants can go away if load is actually getting off the system at certain points.

Speaker 4: This is critical because if there is a retail competition market with an attractive default supply, even with different kinds of portfolios, the less likely the market is going to have a well functioning fifth bucket. And this market component you just described is the most flexible of all.

Session Three.
Going Long: Capacity Markets in Action

If energy prices alone cannot support adequate capacity investment, capacity mandates provide an obvious policy alternative. Mandatory capacity markets with long term commitments have moved out of stakeholder processes and into commercial operation. Significant quantities have been procured at significant cost. As the experience develops, evidence is accumulating to evaluate the benefits and consider the effect of mandates to go long in order to avoid being short. Do the different names (e.g., forward capacity market, reliability pricing model) signify fundamental differences in practice? How

have the different approaches been performing in the early procurements? Are the auction designs working? Are the auction designs evolving? How do the auctions compare in treating mixes of alternative supplies? How do the procurements address transmission issues? What practical impacts are the capacity markets having on electricity markets? What lessons can be drawn from the early experience that might transfer to other regions of the country?

Moderator.

We'll examine several issues today. Does paying existing generators overcome the siting, permitting and investment obstacles created by future legislation? Second, how and when do we decide if these new markets have failed or succeeded? If they failed, what do we do, and will it be too late? Third, is the long-term capacity market auction working, and how has the auction impacted alternative supply alternatives? Finally, we'll consider New England's forward market and how it is working. We'll begin with that issue first.

Speaker 1.

I will give some history of the capacity market in New England and discuss issues as they proceed towards their first auction in February of '08. It took from 2003 until 2006 to get a design and a settlement in place. They filed a locational capacity market like New York's in March of 2004 based on a FERC order.

FERC accepted it but there was so much protest they set hearings which occurred through '04 and '05. The FERC ALJ [administrative law judge] accepted the revised proposal in '05.

However, the NE ISO [New England Independent System Operator] got all the New England states to agree on something, very rare. They all agreed that they didn't like LICAP [Locational Installed Capacity]. [Laughter] Later in '05, FERC and Commissioner Kelleher got everybody to agree there was a problem and got them to work towards a solution. That was fairly important. The settlement process finished in early '06 and FERC ultimately approved it. The first auction is scheduled for February of 2008 that will be for capacity delivery in 2010. The rules are more detailed than any other rules they've filed.

The original LICAP proposal was based on a demand curve. The states strongly opposed this, they wanted a market set price. Now there is an auction to get a market base price.

States also wanted something with more commitment in it than LICAP. Originally, there was nothing contractually that assures capacity will be built. Now there are some financial guarantees associated with it. The resolutions of the demand curve and forward commitment issues really led to the settlement.

Currently there are transition payments until the first auction in February of 2008. Capacity is receiving $3.05 a kilowatt month right now. This "bridge" is an important transition to get the market started. An interesting twist is that NE ISO is paying this to all capacity that wants to come into New England. They are essentially overbuying at this point. The rationale was to get as much capacity as possible before the auction to keep the auction prices low. It will be interesting to see how that plays out.

NE ISO's objective is to buy enough capacity to meet needs three years in the future. It includes demand and supply resources. If a new resource clears in the auction, it has a guaranteed price for five years. They wanted this 5 year commitment as an encouragement to financing; to help improve the market.

There's a qualification phase before the auction to assure project viability in terms of project completion and transmission. A key piece is a descending clock auction. In between the auction, and the commitment time three years later there will be reconfiguration auctions to let people buy and sell out of their positions. They

will occur frequently: annually, seasonally and monthly.

There are also performance incentives. There is an energy option and a requirement to supply energy during shortage hours. This product is a physical capacity, not a financial market. They are buying specific resources, not a commitment to provide a resource. The resource must bid into the day-ahead and real-time market. There is a requirement to provide energy at the cost of an expensive peaker; about $200 depending upon the gas price. In effect, load is hedged at prices just above the index price.

There are qualifications for all new resources, including intermittent and demand resources. The project is rated by the ISO. If someone tells them they are going to bid a nuclear plant in three years, it wouldn't qualify. Same thing if someone tries to hook into a full substation. They try to do reasonable screening so that they are getting realistic capacity.

Existing capacity resources also qualify. If a resource wishes to leave the market they have to submit a bid to called the delist bid at a certain price. If those prices are high, the ISO reviews to see if it is realistic and representative of their going forward costs. If it isn't, it's presumed to be market power and it's disallowed. that is how market power is addressed. People can't leave the market unless they are submitting reasonable delist prices to leave.

The descending clock auction starts at two times the cost of new entry, which is currently $15 a kilowatt a month. Thus, the cost of new entry is estimated at $7.50 a kilowatt month. That's based on studies the ISO did in the litigation to determine the cost of building a new peaker. That number will be replaced with auction results in the future.

Hopefully they'll have more than they need at $15 a kilowatt month and the price will drop in the future. The legal settlement included a collar on the price for the first three auctions. There is a floor of $4.50 and a ceiling of $10.50. Expectations are that the price will be much closer to the floor than the ceiling.

The reconfiguration auctions permit participants to adjust positions, and they happen after the FCA [forward capacity auction]. There's a lot of flexibility there.

One concern is location. The states were concerned about being import constrained and having higher prices than the other states. The import and export constrained zones will be modeled in the auction. If a modeled constraint binds, then the prices are different.

Import constrained zones are not modeled in the auction unless projections indicate a need for capacity in that particular zone. For instance, if they're projecting that Boston will be short three years from now then that constraint would be accounted for. For the first auction, neither Boston nor Connecticut will be constrained in the first auction. It's possible the ISO could be a year behind in terms of dealing with locational problems. It's a small lag.

A big advantage is the ability of demand to participate in the auction. Demand is treated as a resource, and it receives the same payment as supply resources. In fact, demand reductions are grossed up for planning reserves, as well as losses. A megawatt of demand reduction at the meter is worth about 1.18 megawatts of capacity in the market. Performance is critical and there are stringent performance standards. There are two demand types. Active demand reduction occurs when the ISO sends a signal and a load will reduce. The other is energy efficiency. States and utilities can bid these as capacity. The ISO considers the reduction a program causes during peak hours and identifies it as capacity in the auction. There is a lot of it.

The performance incentives are important. They wanted to preserve the incentives of an uncapped energy market in a capacity market design. The better resources perform, the fewer they'll need and the cheaper the capacity market will be.

There are two performance incentives. First, capacity payments are reduced if resources aren't available at critical times like hot days; they must perform or lose payment. It's 5% for

each incident, and there are some caps, but the penalties are significant.

The second incentive is the energy option. Capacity resources have to provide energy when the price exceeds the cost of a peaking unit. This corresponds scarcity pricing hours. In New England, the energy price gets raised through scarcity pricing up to $1,000 when they run out of operating reserves. If a resource doesn't perform then they lose this money. In effect, this hedge's load at the peaker price. If an entity has 10% of the capacity, they must supply 10% of the load during these time periods. This should work well.

A subtle feature is that they are hedging weather risk. In an energy-only market, one hopes to hit $10,000 every year to make capacity payments. This system replaces that with a fixed payment and the requirement to provide energy when prices are high. Further, it reduces the incentive to exercise market power during high priced hours because if it's done with old energy, it gets lost in the capacity payment.

How well is it working? The first auction will be 61 megawatts, quite small. That grows to 805 for the second auction and hits 1500 megawatts by the third auction.

There is a lot of demand response show of interest. 3000 megawatts for a 60 megawatt need. 840 is energy efficiency and 2184 is active demand response. The ISO should have plenty to choose from just based on demand. There is also 10000 megawatt of "show of interest" supply. Most of the capacity is in Massachusetts and Connecticut, where the load is. Encouraging.

Question: Is there a limitation in averaging and lags on this real-time scarcity above $200 as to how much the ISO has to pay?

Speaker 1: No, there are restrictions on the shortage hour piece of it. There are no qualifiers on the reduction for high energy prices. There's a 12 month rolling average but it gets deducted. It's lagged because they didn't want payments to go negative.

Question: You discussed the collar on the capacity prices; can you clarify? Second, does demand have the same peaking energy options – set at the 22,000 heat rate peaker - when they bid?

Speaker 1: First question. There is a collar for the first three options, a low of 450 to a high of 1050. Supply was concerned about the price dropping too low and load was concerned about the price getting too high and ruining auction viability. There is no energy option for the demand, they do not have that deduction from the capacity payment.

Question: How can the ISO determine if efficiency is providing capacity or whether they had a forecasting error that resulted in a lower than expected demand?

Speaker 1: The forecast is going to be what it is. The issue is how do they measure the capacity of the energy efficiency? They have measurement and verification protocols. Let's say it is motors. They determine the motors are in place, when are they operating and how much they reduce the load. They count that.

Question: There would be metering data at the facilities?

Speaker 1: Yes. Each project has a unique measurement and verification plan – usually statistics or metering. It has to be accounted for in the load forecast. If the ISO is buying it on the supply side, they have to count it on the load side to make sure that they have all that what need.

Question: For the de-listing process, does that apply to imported capacity resources, or only resources within the New England region?

Speaker 1: Imports are only for a year so it doesn't apply to imports.

Question: What about dispute resolution? The ISO as a procurer makes qualification judgments. What if people challenge their decisions, how is that resolved?

Speaker 1: There is a lot of detail in the market rules and that helps clarify things. They've had a few resources that didn't follow the rules. Those folks went to FERC and said pardon us. FERC has done that. The ISO applies the rules and if people have questions they go to FERC.

Question: What self-supply options are there? Second, what are the credit implications for the ISO's balance sheet from this market?

Speaker 1: I didn't discuss the self-supply feature. The municipals wanted to self-supply. They can self-supply and take both sides out of the auction. The generation is out and their load is reduced as well.

Second, the financial assurance obligations are not the ISO's. They're tariff obligations enforced by FERC. The ISO is not responsible for $3 billion. The FERC tariff binds the parties as a contract.

A distinction between RPM and this design is the financial assurance is not as great as in RPM. If an entity fails to provide, they lose three month's capacity payment. In RPM, they were responsible for replacing that capacity. This less stringent rule reduces financial assurance, and thus costs. Instead it's been backed up with a more detailed and rigorous qualification process.

Question: Does the reconfiguration of trades have any impact on the auction price?

Speaker 1: No.

Question: Is the demand response under tariff as well?

Speaker 1: Yes, it's a wholesale market. The people providing the demand response are suppliers to the old utilities, as well as companies like EnerNOC and Comverge. It's a mix of participants. They're getting paid through the tariff just like all the other resources.

Question: Is there a penalty if the energy efficiency measure is not there? How is it measured separately?

Speaker 1: There are penalties if they don't perform in the hours in which they're required to perform. The rating gets dropped. There is monitoring, measurement and verification for each on a project by project basis.

Speaker 2.

I'm going to discuss the results for RPM [Reliability Pricing Model Auction] in the PJM market. I'll focus on the two auctions that have been run. Before we get to that, let's consider the urgency that PJM had about this that pushed them towards the FERC settlement process.

There were disturbing trends within their market. The market was expanding, but capacity base was shrinking, by more than half over a period of a few years. There were projected generation retirements that were very alarming. Market rules at that time gave generation 90 days notice to retire. Obviously there is no way to build anything in that timeframe.

This created a lot of RMR [Reliability Must Run] contracts. They called it Generation Deactivation because the RMR name was already taken. There were unit performance issues; they were performing more poorly over time – a trend in the wrong direction. When the markets opened in 1998, there was a big improvement in unit performance. More recently it began regressing. Unit maintenance was also a problem. Some entities were coming to PJM and saying, "look, I'm going to run this unit into the ground, I cannot afford to fix it." This was occurring in the most constrained areas; Baltimore, Washington, etc. This situation resulted in RPM.

RPM is a new reliability construct in PJM. It's integrated with transmission planning. The transmission planning process feeds information into RPM to set locational capacity requirements. In the past retirements would be planned because prices were too low and PJM would deny the retirement request for reliability reasons. RPM would fix that and align prices to alleviate this kind of situation.

The final concern was to create a forward investment signal. The previous capacity market was often short 36 hours in advance. If 11% of the load being covered by capacity is out 36 hours in advance, that's not capacity. RPM was meant to fix this problem as well.

RPM is resource specific three years in advance for the entire planning year. No partial years. Entities can offer existing or planned generation resources. Planned transmission upgrades could be offered too, although that is difficult. Existing in-plan demand response is also eligible. Planned demand response have credit requirements; they have to post collateral. All of the new resource types compete directly with the existing stuff.

Let's look at the RPM process. First there is a self-supply and bilateral designation period. There are several ways that entities can sell supply. A fixed resource plan means the entity puts in a five-year plan to cover their capacity requirements for their load and growth and then this is simply removed. There is also flexible self-supply where they self-supply through the auction. Instead of taking the load out, they simply put their resources and self-schedule in the auction.

Next, PJM holds a base residual auction in which all remaining obligations must be accounted for. There are a series of three incremental auctions afterwards but they do not affect the base residual auction clearing price. These occur at 23, 13, and 4 months. At the second incremental auction, PJM can adjust its capacity requirement based on load forecast changes. Throughout this period, ongoing bilateral activity occurs.

EFORd occurs just before the third incremental auction and refers to the forced outage rate of units. That's where the unit sells forward what it expects to perform at and it's held accountable to that. It's required to offer in, through the must offer obligation, its equivalent availability based on history. If it's under-performing, everyone sees that out a few months before the delivery actually occurs. Then there is an auction to replace the megawatts that are not performing. Generators that are over-performing can sell more. The third incremental auction occurs just afterwards so people can match themselves up.
After the last incremental auction, ILR or Interruptible Load for Reliability is the last item to occur before the planning year comes into play. This is the demand response that could not bid forward three years ahead. It comes in to handle peak shaving. In discussions with demand response customers, some of the industrials don't even know if their factory will exist three years away – they can't bid demand response that far ahead. The ILR provides a place for them.

The capacity prices in the first auction in April 2007 was for fiscal year '07 – '08. The price of capacity RTO-wide was $40.80 a megawatt day. In two areas, there are elevated capacity prices because of transmission issues, $197.67 in Eastern MAAC which is New Jersey, the Delmarva Peninsula, and Philadelphia, and then $180.54 in Southwest MAAC which is Baltimore Washington. In the next auction, the prices went up substantially in the rest of the market to about $112 a megawatt day. They went up a bit in Southwest MAAC in 2010, and dropped in Eastern MAAC to $148.

PJM got about 11,000 over the two auctions. The total amount of incremental demand response was about 1120 megawatts. There was some increase in capacity that was offset with continuing deactivation of a few units. The net capacity increase, though, was about 482 [MW] in the first auction and 923 in the second. That does not match load growth, but it is a good trend. There was a substantial shift in demand response. Demand response actually reversed and began increasing.

The other big trend was a reversal in generation retirements, mostly in Eastern MAAC. Some retirements were postponed. One unit reactivated, which was astounding given the short notice of the RPM. So there have been big reversals and increases in both demand response and retirements.

The jury is still out on new investment incentives. These may take longer to ramp up –

it's hard to know. Auctions are ongoing and they will know about this issue over the next 1-2 years.

Question: In the ILR auction, the last one, when they let the demand response in, is there a set aside requirement for that? The requirement that's been met in the base residual auction, is that reduced so there is something left to procure when the demand resources are coming in?

Speaker 2: There is a forecast of what we expect in this short-term demand response, and they reduce before a procurement to account for that. If there is extra, that's fine.

Question: Why doesn't energy efficiency bid into the auction? I believe New England does that.

Speaker 2: PJM was struggling with how to measure it, and verify. PJM was ordered by FERC to get energy efficiency so now they are working on it. The RPM settlement process occurred so fast it couldn't be done at the outset.

Speaker 3.

I will talk about capacity markets from a supplier and an LSE standpoint. What is the genesis of the need for capacity markets? There is a mandate to go long in most organized markets, with resource adequacy and reliability targets. What's the problem with an energy-only market? Finally, I'll address the long-term contract conundrum for investment.

RAR [resource adequacy requirements] have been implemented in capacity markets to meet forecasted reliability requirements. Those reliability requirements, in all markets, are far beyond operating reserve margins. It is up to double the amount of operating reserve needed on a day-to-day basis. There's a lot of excess for reliability purposes.

RAR is needed to provide structures that bring investment in; to support investment in existing and new resources. The big concern now is whether these mechanisms will support merchant investment or support a return to utility backed investment in infrastructure?

An energy-only structure is desirable, but at this point capacity markets are necessary. Price signals for capital expenditure are needed. The markets are all structured with various forms of mitigation: bid caps, RMR contracts, out of merit dispatch. These manage and/or prevent price spikes but also blunt the energy and ancillary services price signals to incent investment. They provide a regulatory hedge to load and create disincentives for other hedging mechanisms, including new investment.

In an energy only market an entity hopes for the $10,000 price so they stay in business. More importantly, without the threat of a $10,000 price during a weather event, nobody is incentivized to do the contract to manage price exposure. Without these incentives we need capacity markets, some call it messy money. The RAR in capacity markets reinserts incentives that the mitigation took out.

All capacity markets employ planning reserve margins that exceed operating reserve margins in the energy and ancillary service markets. They all have differentiation for load pockets. They've all created mechanisms to provide new entry price signals. In New York it's a demand curve. In PJM it's a forward auction with a demand curve. In New England it's the descending clock auction. All of these mechanisms provide information to the marketplace about the cost of new entry.

They also all have robust qualifying procedures. DMNC [Dependable Maximum Net Capability] testing, summer and winter ratings, cataloging of forced outage rates, etc. They have performance incentives and/or obligations imposed on the resources. The have to bid into the day-ahead market. In New England and California they're required to bid into the real-time markets as well. There are market mitigation measures to make sure that the prices are capped in some form or another. They provide mechanisms for shifting capacity among LSE's as their load shifts; load migration.

There are only a couple of small differences. First, the timing of the resource commitment verification. Both New England and PJM ensure resources are committed to the market several years in advance. In New York the commitments aren't verified until a month ahead of market. Both PJM and New England have specifically outlined backstop mechanisms if new entry is not occurring. They provide procurement on behalf of load that hasn't shown up in the primary mechanism in the market. New York does not have a formal backstop mechanism in their model.

The second difference is price discovery mechanisms. Both PJM and New York employ a demand curve approach set at a level that reflects the cost of new entry of a marginal unit in the system, plus the peak energy rents that would be expected for that unit to earn. The price is not allowed one step past that. Between that point and the point where additional resources bring no additional value to the system they set a demand curve. This establishes a range of price signals that tell the marketplace what capacity will cost if they don't hedge. It provides a price signal for buyers and sellers in bilateral transactions.

What are these capacity markets expected to do with respect to investment? This is the long-term contract conundrum. While all three Eastern market RTOs have a capacity market structure, there are still calls for utilities to re-start investing. Should utilities add rate base generation? The capacity markets need to create incentives for long-term contract hedging or we need to return to utility investment with regulatory guarantees. Those are the two ways that we can get the necessary commitments to induce new investment.

What are the market implications of these two approaches? The regulatory guarantee contracts certainly do create assured resources. However, once these contracts start operating in an LMP-based market, they depress LMP price signals. This creates a spiraling effect of needing more regulatory guarantees because the price signals for merchant investment simply don't exist. It's a vicious circle.

This issue of merchant investment versus regulatory guarantees is binary. Merchant investment becomes impossible in a regulatory guarantee environment. The risks are simply too high. Under regulatory guarantee contracts, the full life cycle risks of plants are cost pass-throughs. It's central planning as opposed to active risk management. The market loses competitive pressure for increased efficiencies and the technological innovations. It discourages new entry and imposes investment risks on consumers.

If capacity markets create market stability with a suite of energy, ancillary services and capacity market price signals that are capable of supporting investment, what are the market implications of that? The long-term utility contract is replaced by long-term market stability. Investors can go out and analyze the market supply and fundamentals. They can analyze the value of different portfolio approaches including capacity, renewable energy credits, emission reduction credits, ancillary services. They have flexibility in portfolio management, optimization of products and services with varying terms and conditions. There is an important role for market intermediaries who are experienced in constructing portfolios and managing the price arbitrages. This creates a robust wholesale competitive market, which in turn provides the framework for retail competition. This requires allowing the price signals to emerge that they need to respond to, let competition flourish and not undermine that with regulatory intervention.

Backstop mechanisms can be a problem. They create a self-fulfilling prophecy of failure for the underlying market structure. When there's a backstop mechanism prepared to offer a 10 or 15 year contract under criteria that are less than crystal clear, it enables the primary mechanism to fail. There is a real concern for entities sitting and waiting for the backstop to procure. Fortunately, the early PJM results seem to be encouraging.

Ultimately, it's energy and ancillary service prices that will incent demand response. If consumers see real price signals and turn off

usage at high price points then the right thing is happening. Keeping the energy and ancillary service prices tightly tied to the capacity market is important. All the markets calculate cost of new entry pricing as a function of the cost of new entry less the energy rents available in that market. They will also need to reset net cost of new entry on a regular basis when markets are undertaking efforts like improving their scarcity pricing, designing ancillary services that allow for better wind integration. This will put more of the value of the resource into the energy and ancillary service markets. The residual amount that's needed through the capacity market should decline over time.

The New York model has some nice characteristics. They have a capacity obligation on the market one year in advance. They use a demand curve that is based on the cost of new entry less the expected peak energy rents, along with a cap and a point at which that curve crosses zero. It is set for three years at a time. The market always has information on the requirement and the real time price if they don't hedge. At the month ahead market, entities submit all of the bilaterals that they've committed. Other resources that aren't committed can also offer in the monthly demand curve auction. The price clears on the demand curve that intersects the supply curve. And this has been in effect since 2003.

The results are encouraging. The excess above minimum capacity requirement increased in summer periods from 5.5% in 2003 to 10.3% for 2006. Their winter excess increased as well. New York also saw capacity import entities maximize at their 2755 megawatt capacity for imports almost immediately. Now they are seeing some exports, that's very healthy. This is also because both PJM and New England have capacity markets that are better reflecting the value of capacity. We will start to see some very rational capacity conditions region-wide.

In New York, generation in the interconnect queue has increased significantly. Demand response has increased to over 1000 megawatts in the summer of 2007, a 12.5% increase from the prior year. Unit performance has improved so much that the planning reserve margin has been reduced from 18% to 16.5%.

Speaker 4.

I am going to present views from the purchaser side that are challenges to the capacity markets. These need to be addressed and/or overcome in order to help these markets succeed. There is a missing money problem. In an energy-only market, generators do not get paid unless they run. Generators cannot be dropping off the system because they're not getting paid.

There are three ways to address the missing money. First is scarcity pricing for the energy market only. That is simply politically unacceptable. Second is the capacity market, which is the focus we're talking about today. Finally there is a hybrid model. MISO, for example, is experimenting with a hybrid approach.

The RTOs in the Northeast previously used an unforced capacity model. Capacity is procured through bilateral markets or auctions. If load did not procure enough capacity they face high deficiency charges. The intent of the deficiency charges is to incent the bilateral contracts with auctions as a backup. The challenge is there is an oscillation between a very low and a very high capacity price. Prices were as low as $5 per day up to $160 per day but with very little in between. That volatility was probably responsible for the declines in capacity the markets were experiencing. The previous markets were successful because they provided multiple options for purchasers to get the capacity, you could either get it bilaterally or through the auctions. Another problem was that there were not very good signals for location. RMR contracts started to become more prevalent because of this. This is what leads us to the forward capacity markets that have been described by the previous three speakers.

Let me focus on some concerns in PJM. The price in the RPM auctions are established by the intersection of the demand curve, the variable resource requirement. Essentially, the. The

reserve margin that's procured also varies dependent on the intersection of those two curves. What can happen is a target gets established just above the installed reserve margin in which they end up procuring more capacity. They could be procuring 4.5% above the installed reserve margin; a 4.5% excess.

This creates an uncertainty on the obligation. In the older markets, the load was specific, now it's uncertain. If one is trying to build generation or trying to sign a forward bilateral contract to serve the load, there's uncertainty as to how much is needed.

A second RPM concern is the forward commitment. It does have some significant benefits. It allows generation to offer into the market in return for a guaranteed set price. They know what price they will get, and can decide whether to build based on that. It gives PJM the certainty three years forward that there will be enough resources in the ground. It allows PJM to instigate the back-stop that's been discussed. However, it eliminates or decreases the ability to create bilateral contracts. Once the three-year forward auction is run, there is not much ability to procure capacity outside of auction. The prices are established. There is no reason to sell capacity at a price lower than the auction clearing price at that point. One must procure it prior to the three-year auction point or use the auction.

As beneficial as it is for generators to know the price ahead of time, it can add risk if one does not know whether your generator is going to be there for the next three years. This is a concern for some of the smaller resources. If it is uncertain whether your resource is going to be there and one has to commit three years forward, that involves risk. That risk ultimately translates into higher prices.

The locational aspect of RPM is useful but there are limitations too. Isn't LMP supposed to do this? It does to some extent but not completely. It's an imperfect mechanism. There are higher prices in the constrained areas. In the past purchasers bought 20 year contracts or even built resources in far away places. They were fully hedged with these resources. With the locational concept, they're no longer hedged. For example, LSEs on the Delmarva Peninsula helped build facilities in Western Pennsylvania. Now they are paying huge price differentials for this power because of the locational differences.

Finally, in 2006, 2007, the prices in general were less than $10 a megawatt day. Now prices range from $40 to over $200 in some constrained areas. The concern is whether these prices will provide an incentive to new generation or just provide a windfall profit to existing generation, or perhaps a mix of both. Purchasers are not necessarily opposed to paying for capacity, but they do have concerns about such high prices. Hopefully the recent signs of market response will maintain as a trend.

Some areas may be immune to incentives, no matter how large. New Jersey is very constrained. One cannot plop a generator down in New Jersey overnight. Environmental restrictions are getting tighter with other permitting issues, and forward price uncertainty.

Part of the goal of RPM is to work with the transmission planning process. It does help develop new transmission with a pricing signal. It allows transmission to participate in the auction. Developers get the price difference by offering in transmission, and entities who built transmission in the past are now being paid for having built that capacity. However, it's important that transmission planning occurs on a longer horizon than the three year forward.

Question: With a three-year forward time horizon, the only actual new entrants are short time horizon, upgrades to existing facilities, combine cycle projects, stuff one can build two years, and some demand side. However, base load generation of scale, coal or nuclear are six to twelve years. How does this help those kinds of projects?

Speaker 2: Initially capacity prices were artificially depressed because the capacity market only looked 36 hours out. There was no forward price signal showing what capacity will be worth. 15-year guaranteed contracts have

name, it's "regulation." The RPM sets backstop prices for folks who don't implement a forward contract. The RPM auction should not be the main place that people procure their capacity. It should be on long-term forward contracts.

One industrial customer in PJM said simply that we have to make the spot market less attractive in order to create long contracts and create incentives for large scale base rate. Make it painful for people to take LMP at spot price. This system does that.

Speaker: The auction was never intended to give enough lead time for all resources, just some lead time. It was never intended to be the only source of revenues for generators. A new nuclear plant should not be built based on capacity revenues, it's an energy market decision. The capacity market will have some beneficial secondary effects along the way, but the primary decisions factors will be derived from broader energy market factors. Capacity is just a piece of the overall market structure. It's not the whole driver for everything.

Speaker 3: I agree with everything just said. One further thought is that capacity market structures create price signals that are stable, predictable, and forecast-able. If overall stability is achieved, it creates a much better environment for large scale coal and nuclear investments.

Speaker: The three years period was chosen so that short-term new entry could discipline price.

Question: The last speaker discussed how Eastern utilities who had purchased capacity in Western Pennsylvania were at a disadvantage with locational prices. However, at least some of them have sold off their capacity in those Western plants, but they have entitlements and obligations on the transmission system. How are they disadvantaged?

Speaker 4: In '07, '08, a generator in Western Pennsylvania was getting paid $40. The load in New Jersey was being charged a net price of $143. That net price reflects capacity transfer rights that are given back to entities to reflect their import capability. Even with those credits coming back, there is still almost $100 price difference between those two areas. Loads get no revenue stream coming back to offset that capacity difference.

Question: Even though they've sold that capacity but still have the transmission rights?

Speaker 4: If they've sold it, that's a different issue. I was describing purchasers who still have the capacity and need it to meet their load.

Question: What about a market to provide more liquidity or efficiency around the bidding or hedge products? Where capacity payments are differential across regions and people are trying to hedge the exposure. A financial contract could allow or compliment that.

Speaker: Actually RPM has helped to foster some of the financial markets. There is a robust side market to hedge capacity congestion. Also, some developers get incremental capacity transfer rights for transmission. They don't get credits until the actual delivery year begins. There's some activity to sell those for a slightly lower value to get upfront dollars. Several examples already.

Speaker: RPM has drastic penalty. However we've seen generators committed to RPM, and three months later their turbine blew up. In the past this would have been an automatic retirement. Now they're spending a lot of money to get it running and avoid the penalty. A financial side market in this absolutely needs to develop. There shouldn't be financial products in the market itself, but a side market would be fine.

Speaker 1: Having this be a physical market was very important to the settlement. Integrating a financial component would be very difficult but a separate market developing on its own bilaterally would be good.

Question: Utilities really want to see capacity markets work because they can get out of the business of signing ten-year contracts. They don't like the debt equivalence. They want out, or at least have the option to use it as hedging.

However a lot of the response we saw today is small scale, demand response, taking existing plants, avoiding retirements. We still don't know about new capital investment and real new capacity. Will the banks get confident quickly enough, and over the long-term, to finance via a three or four year ahead signal? Will policy makers remain comfortable with that? If capacity is not coming quickly, policymakers will want to rush to the backstop. This has happened in California.

The last concern is regulatory stability. We have seen companies with $ 1 billion dollar write-downs after the regulatory paradigm changes. Can we count on these markets to remain stable?

Speaker 1: New England had 10,000 megawatts of expressed interest in new generation. So, it should be built. Several folks have suggested that we should be building base load and it's not happening. I'm skeptical about that. We probably should not be building base load based on the prices that are out there.

Question: Let's include peaking capacity too.

Speaker 1: For base load a new coal or nuclear plant is a difficult economic proposition with gas prices where they are and where they're expected to be. If capacity markets don't create base load resources, it's because of the overall economic climate not the capacity markets. It's important to distinguish between overall energy and economic effects, and the effects of the capacity markets.

In terms of regulatory stability, it's not a capacity market issue either. That's just an issue for this industry. [Laughter] Capacity markets aren't going to solve it. They have to deal with it, I agree, but it's just an issue.

Speaker 3: Three years ago the word "merchant" was not being used. It was a ten-year contract with ironclad returns and recovery. Now New England is comfortable with a five-year backstop. The rhetoric from the investment banks has declined from a 20-year PPA to a 10-year PPA. The markets are starting to support investment. They know the backstop is there too. Market stability takes some time to form. There have to be mechanisms for bringing the investment in during these transition periods, but it should minimize the harmful impact on the emerging markets.

During this transition period there will be support mechanisms for things like IGCC and nuclear. Mechanisms that are a lot less intrusive on markets include loan guarantees for nuclear. Loan guarantees are better than some kind of direct PPA contract off-take. We should look for similar mechanisms in the environmental debates as well.

Speaker 2: PJM has been dealing with incremental transition start-up options. Folks had only a few months notice so the short-term stuff was the only stuff that could come in right away. We will see investment in combined cycle peakers for sure. The other stuff has many mitigating factors.

Speaker 4: Base load resources don't necessarily look at capacity revenues. They make decisions based on the energy revenues. That is because there's no certainty on the capacity revenues. Now, base load generators can count on these $140 prices with more certainty – it can only help.

Regulatory changes are always possible but RPM has been talked about for eight years. It looks pretty stable so far.

Question: For regulators, how much confidence is there in these markets that they're going to be stable and stay around? Given what we've just seen in Maryland, with the commission in Illinois. Things can flip very quickly on the political front. That scares the financial community from investing. How much political, legislative, public policy pushback are we seeing that the prices are too high?

Moderator: There is no litmus test. You cannot predict what lid will fly off the regulatory pot at any time. [Laughter] PJM states has 13 very different states. Regulators work to remain independent but there are pressures. Most regulators aspire to regulatory stability.

Comment: Regulators in Delaware were uncomfortable with the market prices in the capacity market. The knee-jerk reaction was to take control back. During this uncertainty period, there is a concern.

Some fixes are not attractive. Some states are looking at ways to take control back. They want longer term solutions. Some say the fix is to go to regulation. That is quite entertaining after we've been told let's deregulate.

Question: One speaker described how market structures provide forward prices that allow hedging of risk. However policymakers in California may create mandatory action to hedge risk. How does mandatory hedging fit in?

Speaker 3: Well, the obligation is already there. RAR requirements impose the obligation to be met, and all of the capacity market models ensure that resource adequacy requirements are met. The only question is when that commitment is announced.

Perhaps hedging should be required in the forward market but not through utility guarantees. Parties who have obligations to serve load or the desire to serve load because of customer choice have to be hedged in order to offer products and services to their customers.

If the utilities retain the default provider service, how do they hedge the risks associated with that? The best way is to auction their load off and specify exactly what their load profile looks like, what changes it's subject to, what are all the products and services that they're required to demonstrate to PJM that they have in their portfolio. Whether it's renewable credits, emission reduction credits, capacity credits, energy; ask for those products and services from the market.

Stable market structures are only good in so far as they create entities that offer products and services out of them. Market intermediaries, wholesale marketers, investment banks all have a role in creating innovative portfolios to serve that load. They'll assess market supply and demand fundamentals embedded in the capacity market price signal, along with the energy price signals. They can fit into this situation very well.

Question: What about the interaction of the new reliability standards and capacity markets. Does this make things easier or tougher, or are they totally parallel and independent?

Speaker 1: In New England, they've been meeting the NERC reliability standards for 35 years. It's not an issue. If it did become an issue, it would flow through the ISO's requirements calculation. They calculate that every year. If the NERC standard changed then it would be factored into the requirements calculation. It's independent of the market design.

Speaker: The RPM creates complements that help reliability. but overall it has not changed anything.

Question: So the market requirements exceed the reliability requirements?

Speaker: No. The market requirements are driven by the reliability requirements, but the incentives for generators to perform is enhanced because the performance requirements that used to be within PJM, are much less rigid under RPM.

Speaker: Which, essentially, is actually great for reliability.

Question: What happens when someone goes bankrupt in these capacity markets? How does the system respond to someone who has won the bid and then doesn't deliver and isn't going to pay that penalty because they're gone or they never came around? What happens?

Speaker: In PJM if there is a generator that commits itself and then cannot produce, it will start incurring penalties. If there is no longer an entity to allocate the penalties to, barring what bankruptcy courts might do, that underpayment gets socialized across every other market participant and generator in PJM. If someone commits and doesn't deliver, everyone t ends up paying for that.

Question: What about the physical part? What if the capacity that was promised isn't there?

Speaker: First, the installed reserve margin is a planning requirement. PJM's obligation is to plan for 15.5%. If they get down to 12% or so, they're not violating any reliability requirement. If they lose one or two generators or a few hundred megawatts that's why they are over-committed in the first place. Now, if it got severe enough with very low capacity then PJM would find other ways of procuring that capacity.

Speaker: A bankrupt resource would forfeit their financial assurance money. If bankruptcy occurs then that would all flow through the bankruptcy court. If the court kept the plant running, it would keep getting paid, if they got shut down then they would stop getting paid and PJM would procure additional capacity through the next reconfiguration auctions.

Speaker 3: In PJM and New England, if new resources come in, there are specific milestones that they need to achieve, the same as one would have in a bilateral contract for new generation between two parties. If the developer does not meet them, they have to replace or pay damages. A shortage would not sneak up on the ISOs.

Question: One speaker discussed the long-term contract conundrum. This is the risk that prices may be depressed in long-term contract so they wait for an alternate recovery mechanism through a contract with a regulated company. If transmission is getting built on a regulated or mandated basis to address large price differences, is there an economic planning conundrum where the impact on price signals depresses the incentives for new resources to come in these capacity markets?

Speaker: When, and if, generation has really returned to competitive market forces, the next conundrum becomes the generation versus transmission conundrum. That one isn't going away. Transmission is treated fundamentally different than generation. It takes longer to build. The challenge for the ISO transmission planning exercises is to evaluate transmission versus generation and not negatively impact the competitiveness of generation. This is difficult. However, it is easier and more transparent if the generation infrastructure is taking part in competitive procurement. The generation market cannot expect rate-based capacity or other type of long-term guarantees. The competitive market environment can feed into the transmission planning exercise. Since transmission gets a regulated guarantee it is always going to create evaluation difficulties for transmission versus generation. Robust and valid price signals in generation will create a more rational transmission planning process.

Question: To what extent are the banks going to take this revenue stream into account beyond the 3-5 years, because they perceive it as a stable piece of the revenue stream from these markets? Where are the banks on these markets?

Second, could speaker 3 comment on the conundrum aspect of why long-term contracts will only occur in fully regulated or completely competitive environments; the either/or question? It's never going to be either/or because some states and regulators want some control because reliability is so critical.

Speaker 3: For the banks, the rhetoric about the length of the contract or the PPA has changed. Citibank is more concerned about the importance of market stability than the length of the contract. In California some investment banks advocate that California be set up as an energy-only market. Goldman is part of that approach. Obviously, the energy-only approach entirely relies on market stability to be successful for incenting investment.

There is a lot of money waiting to invest in capacity and invest in electricity resources. How long do these market structures have to be in place before we see new investment? I don't know for sure, but probably within a few years.

Speaker 2: A lot of the investment folks have been contacting PJM staff in the past three months trying to understand all this. Their attitude has changed from skepticism to an understanding that this is really in place and the

price is really going to go up. The change in capacity price from $40 to $112, and the fact that there is a transparent reason for this. They can see and understand that the market is projecting 2% load growth and there's no investment. They now understand that prices are guaranteed to go up. They don't want a 10 year contract, they want a stable market and a 5 year contract.

Speaker 3: The second half to that question was directed at me. Why is utility-based investment versus merchant generation a binary kind of problem, and is there a way to make is less binary. One is never going to move the markets away from some level of utility backed contracts. Recently, the regulatory bodies in the Northeastern states have reconsidered whether they want their utilities back into the generation business.

The market structures were not properly set up to support divestitures and incentives for new generation. Mistakes were made, these capacity market models attempt to correct it. It's binary because it keeps us moving in the right direction towards markets that support merchant investment. If we are going to have utility-based investment, it needs to be done very carefully, with contracts as short in term as possible to support the megawatts as absolutely needed. Utility backed investments should be painful so that incentives are there for the market structure to support investment.

Backstops are an extreme device. If they are needed, something is wrong. Before they are triggered, PJM needs to see what's not working right. If they need to employ utility backing, that's OK, but it needs to be the exception to the rule. As long as market operators layer these checks and balances, and a commitment to market structures, it can be alright.

Question: Suppose that all these demand response initiatives come to fruition and there's enough that the real-time market can clear. What do these forward capacity markets look like? Do you need the forecast demand? How do they change?

Speaker 3: Capacity markets are gone. They're gone when we get there.

Question: They don't even become a hedge?

Speaker 3: If there is demand response that can reduce real-time energy requirements to a level that can be met by the existing resources, the only way we're going to get that kind of response is to have a lower planning reserve margin. We need to have the market operating at an operating reserves level. It's that kind of price potential that will incent demand response.

For instance, in New York once that occurs, there is demand curve pricing at the cost of new entry plus all the value from the energy market. It's going to be almost all of it. There's going to be a negligible amount that's left in the capacity pricing structure if there is really robust demand response.

Speaker: It's important that the price get high enough so that people actually do that. Currently, the capacity markets are substituting for energy prices of several thousand dollars a megawatt hour. Until those kind of real energy prices are an actual reality then the capacity market structures are needed as the way that to flow money through and get the response. It's a framework to make up for the lack of the retail pricing. If the capacity price ever gets to that level, the capacity price automatically goes to zero.

Speaker: I would guess the price has to be above $1,000 for this to happen.

Speaker: This year there were some $1,000 prices in PJM. There was some demand response, but it certainly wasn't anywhere near the magnitude to negate all the demand

Speaker: Yes, but most of the demand doesn't see the $1,000.

Speaker: Right. Good point.

Speaker: As soon as demand can see the $1,000 and be able to respond, you'd probably get a strong response. I'm not sure whether the right

number is $1,000 or $500 or $10,000. There's no empirical evidence. If there's an anticipation where you can voluntarily get off the system, it's a completely different paradigm.

Question: What if the demand response doesn't show up?

Speaker: If you've committed to be demand responsive and told the market operator what that price is, there is a little circuit breaker on your meter. When the price goes up there, the operator presses the button and you're demand responsive, like it or not.

Question: OK, but there is no NERC standard for capacity, nor will there be because Section 215 of the Federal Power Act has prohibited it. Now, PJM uses its long held 0.1 day per year LOLE [loss of load expectation]. If there were an enforceable reserve standard, wouldn't the capacity markets with demand curves inherently violate them when they ended up to the left of that standard? Is that good or bad?

Speaker: It's bad.

Question: If there's a 15% requirement and the demand curve allows one to end up at 14% or 13%, it violates that standard.

Speaker 1: In the New England LICAP proposal, the price goes up at a very high slope so that it wouldn't happen. I don't know what the market operator can do about it. They can buy resources on the short-term through out-of-market procurements. The market is designed not to run short. Obviously, it's a possibility. If it actually happened it would be bad. However, the fact that prices would go through the roof is important.

Question: It's my understanding that it's not a reliability violation not to have capacity. It's a reliability violation if the operator doesn't curtail to get to that position. The operator always has the opportunity to curtail. It may be a serious financial violation or get them in trouble with a utility commission, but there's no reliability violation if they're curtailing or throwing load off the system.

Speaker: In real-time. There is a difference.

Question: If they kick people off the system, it's failure to meet load but it's not a reliability violation.

Moderator: To clarify, a moment ago you said the capacity market is substituting for payments of several thousand dollars but is it not several hundred thousand dollars given the standards?

Speaker 1: No, the several thousand dollars is based on the cost of the number of hours of shortage historically divided into the cost of a peaking unit. This becomes around $4,000 a megawatt hour.

Moderator: But that's not one day in ten years. That's 12 hours a year.

Speaker 1: No, that's a supply side number. That's based on calculating what it would cost to buy the supply to keep the lights from going out. It's not the value of lost load. That's different, and I agree with your point that we really don't know what people want to pay. The one day in ten year engineering standard may be very, very extra reliable or unreliable. We really don't know.