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HARVARD ELECTRICITY POLICY GROUP
FIFTY-FIRST PLENARY SESSION

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RAPPORTEUR'S SUMMARY*

Session One.
Nuclear Power: Are the Stars Aligned?

The stars are aligned for the nuclear power comeback. Concerns about carbon-emitting resources and reliance on the Middle East for energy supply make nuclear energy more attractive from both environmental and national security perspectives. Volatility of natural gas prices makes nuclear fuel more attractive economically. Low marginal costs provide an economic incentive for developing nuclear plants. Potential investors claim to have learned the lessons of the past by offering new technical, engineering, and business approaches to building and operating nuclear facilities, such as improved technology and design, using consortia and/or partnerships operating fleets of plants rather than individual boutiques and international sourcing. Greasing the wheels for development are government provided incentives of loan guarantees and other mechanisms, as well as regulatory incentives and "streamlined" licensing processes.

On the other hand … Is the public over its Three Mile Island, Chernobyl induced reticence to accept the risks of an accident? What about the waste issue? Will we reconsider reprocessing or open up a national depository? If not, can a plant be sited when the location will forever host the storage of radioactive

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

waste? How will the enormous capital investment, with the long lead times required, be financed? Can anyone other than a regulated utility afford to build, operate, and take on all of the risks associated with a nuclear facility? If subsidies are required, to what extent, if any, will those subsidies "distort" capacity and energy markets? How well will "streamlined" licensing fare in terms of public acceptance and judicial review?

Speaker 1.

I will address nuclear power from a public investment standpoint because the industry's renaissance depends heavily on the country's public policy choices. It cannot happen if it's dependent entirely on private capital and investment decisions. The last 30 years have established that nuclear power plants cannot be built in restructured electric markets or the traditional regulatory framework.

Let's examine the current status of the industry. First, there is little nuclear construction occurring in countries that have extensive nuclear fleets such as the U.S., Germany, Canada, Japan, or France. Second, despite this there has been an enthusiastic idea that there is a "nuclear renaissance" occurring. In 2005 there were 40,000 mentions if one googled the phrase. In 2007 the same phrase got over two million hits. While the phrase "nuclear renaissance" is a real growth industry, the actual rate of capacity addition is very low. Indeed, in 2006, although this was probably an aberration, there were more nuclear megawatts retired in the world than added. That was not true in 2007 for instance. Nonetheless, actual capacity growth is extremely slow. but the slope of this line in any case is very different from the slope of the line of mentions of the renaissance.

Further, Joscow and others have shown that nuclear capacity drops dramatically as licenses begin to expire around 2030. The last piece of data is encouraging however. The industry has attained a very good rate of output improvement over the last 15 to 20 years. The reason nuclear power is still at 20% of overall US electricity generation is because of the extensive output improvements in the existing plants. Capacity upgrades have added about the equivalent of five plants in recent years. However, the big difference is that plants have gone from 70 to 75% of their potential output to a little over 90% now. That has improved the economics substantially.

Going forward, there are three rough potential development patterns or cases. The first involves public policies intended to advance nuclear power as a big part of the antidote to climate change. The second is to set nuclear power at its current status quo 20% share. The third possibility is to see what kind of a market verdict occurs in response to climate change and carbon markets.

The first climate change case would involve very substantial growth. Incidentally, even a substantial growth scenario would probably only achieve 10-15% of what climate change experts argue is necessary up until 2050. This takes a very substantial effort to achieve. The U.S. share of the Pacala/Socolow wedge would be about 300GW by 2054. This assumes replacement of all existing U.S. plants in addition to 250 new plants at a cost of about 5 billion each. This rounds out to about 1.25 trillion dollars plus additional costs for waste repositories and enrichment. Clearly this is a major public investment challenge.

To make this happen would require several things. Both politicians and the public would need to believe that this was the only feasible way to get substantial greenhouse gas reductions. Prominent environmentalists would need to sign on or at least acquiesce to such a plan. It would require a major expansion of the loan guarantee program or some other form of federal support. This would put some of the costs in the federal budget, making the plants viable in competitive power markets and/or charging costs to customers in states with regulated utility systems through preapprovals, and assurances that even if plants are canceled prudent investment would be recovered. It's a real question whether Congress and the states could step up to do that kind of thing. A discussion of that, and of the Pacala/Socolow wedges can't fit in here in greater detail but it's a big question. These plants are an expensive way to deal with climate change. There may be a case to be made for going forward with a very limited number to test new designs, as well as the construction and licensing process.

Historically, there has been a substantial Congressional propensity to devote large amounts of money to investments that don't make economic sense. One need only consider our history with enormous irrigation or dam projects to remember this. One can't dismiss this scenario just by saying the economics are shaky. A large nuclear renaissance has significant issues for proliferation. The Carnegie endowment has mapped an expanded nuclear renaissance; to indicate where a lot of the plants would be built. There would extensive building in China and India and dramatic expansion of nuclear power into new countries focused in the Middle East, North Africa, and Indonesia. We could expect to see more of the kind of issues we are seeing currently with Iran.

For Congress to embark on a large nuclear investment requires several things. A strong federal agency with a clear mission or mandate. Extensive congressional sponsorship with a sense of urgent national need and the implication of other economic benefits such as job creation. Local support is needed, this is probably the most difficult condition. Finally, there has to be a willingness to pursue nuclear even if other more efficient or cheaper options exist. Most of those conditions exist currently.

The industry has to reconcile different pictures of nuclear power that they have presented to regulators, Wall Street, and the NRC while at the same time convincing Congress of the opposite. That is, for Wall Street they assert this is a mature technology but for Congress they argue there's a lot of risk and uncertainty involved for purposes of the loan guarantees. To Wall Street this is a mature licensing process, to Congress it's an untested licensing process. They argue to Wall Street that there's much greater public support than in years past, to Congress there's a group of vampire interveners out there just waiting to slow down the next round of nuclear plants and therefore legislative support is needed. This support includes favorable NRC appointees, loan guarantees and other hedges against risk. Doug Koplow of Earth Track has come up with a term "policy enhanced investing." He argues the industry is overtly attempting to get investors and customers as allies, emphasizing low marginal costs of existing units rather than subsidies needed for new units. It's a strategy that shifts risk from developers and investors and increases returns to them. The basic point is to transform the taxpayer and the customer into investors to put up the money that Wall Street isn't willing to.

The second scenario, the 20% share, simply maintains the industry's current stake in production. The numbers are smaller; about 1.5% growth to maintain 20% requires around 200 GW by 2054. This will still require the development of about 166 plants or around 1.1 trillion in investment plus more for fuel and waste. In the last three years Congress has had several supports. The most important ones are the 1.8 cent per kilowatt hour production tax credit and the 18.5 billion in loan guarantees. It seemed like a lot but now it's only enough for 2-4 plants. Certainly these kinds of supports would be needed going forward.

Weidenbaum et al have argued against using loan guarantees. From a federal budget perspective, it distorts potential investment among energy sources. There's also a substantial distortion in the allocation of federal borrowing power if a major commitment is made to using federal credit support for a particular energy source. In other words making more money available reduces interest support for other important issues in the economy that includes small business investment, schools, and mortgage loan support. Finally, loan guarantees undermine credit markets because it reduces the ability to determine true risk.

Loan guarantees also distort power markets issue because they make nuclear power seem cheaper relative to other energy sources when in fact it's not. For instance, energy efficiency would certainly do more faster and cheaper with regard to climate change. This doesn't even address the concerns for cost overruns. Originally, $4 billion was allocated in 2005 for nuclear loan guarantee cost overrun. This was supposed to prime the pump for the nuclear renaissance. In two years the industry said 50 billion was needed and Congress recently allocated 18.5 billion. The jump from 4 to 50 billion without ground being broken on a single plant really sets a new record in terms of the cost overrun history of nuclear power.

The default risks are real. In the 1990s Moody's estimates the industry's rescue between 50-300 billion in stranded costs to customers. Loan guarantees charge taxpayers instead of customers. I suspect these future costs will go much higher. Default risks continue when the plants are built; 51 have shut down for a year or longer. More than half of all plants licensed by the NRC in the 70s and 80s were canceled so the canceled plant issue is also a real one. The West Valley reprocessing plant closed in 1972 with an 18% lifetime capacity factor. New York got a $250 million cleanup bill and the U.S. bill was $5 billion.

Let's discuss the change in political climate. Some argue things will be OK because the federal government is strongly supportive of nuclear power. In fact, we're in the second nuclear renaissance. The first came in 1980 during the Reagan administration. The industry's reaction to that election was halfway between ecstasy and euphoria. What actually happened in the 1980s was much closer to Ralph Nader's vision for nuclear power than to President Reagan's. However, there were no new license applications, the reprocessing plants built in the 70s never opened, the only breeder reactor then under construction was canceled, and the waste repository date slipped more than a year for every year that went by.

Clearly, strong political support alone doesn't guarantee favorable outcomes. There are sincere advocates out there but every argument put forward for a large scale nuclear renaissance today has echoes in arguments that were made with equal sincerity in the 70s. Standardization is just around the corner, we'll reduce dependence on middle eastern oil, it'll clean up the environment, cost controls will be used. These are not new visions for the industry.

Finally, advocates argue that loan guarantees are needed because investments are too large to expect the private sector to make them. However, it's not the size of the investments, it's the riskiness that deters private capital. The TransAlaska Pipeline cost some $7 billion in 1970s and was privately financed.

The ingredients for a sensible nuclear renaissance would be a much more gradual process. It would eventually command the support of private capital markets, successful participation by the industry in competitive power procurement markets not supported by government guarantee. Obviously the waste disposal program needs to provide greater certainty as to where the spent fuel will go. Finally, the non proliferation regime needs to be adequate to the challenges of providing both fuel and waste services that are of concern from a proliferation standpoint. To do this requires creating real carbon markets, sensible research and development priorities, and getting away from a sense that Congress can pick a particular energy source and allocate substantial resources in that one direction as a politically preferred climate change solution.

Question: You had estimates of how much it would cost to build out a fleet to satisfy the wedge or to maintain the current share. I'm wondering how much that 1.1 or 1.25 trillion compares to what was spent to build the existing fleet, including the plants that never made it.

Speaker 1: It's a good question and I don't know the answer. For plants that were completed, and putting aside the need to bring the dollars forward current year, I'm guesstimating an average 1-1.5 billion for 100 plants. So 100 to 150 billion in past dollars but that doesn't count the money spent on canceled plants.

Question: You had the range of stranded cost going from 50 to 300 billion. Is this a large number? Because the 300 billion stranded cost recovery seems like something under the iceberg that's not being addressed.

Speaker 1: That was Moody's estimate of total stranded costs which was largely nuclear. It did include independent power producer contracts that were above market and that had nothing to do with nuclear. So some part of that number is not nuclear and some part of the nuclear cost wouldn't have been stranded. Relatively little of the nuclear cost would actually have been stranded the way the markets have actually played out. Natural gas prices are high and nuclear power is doing fine competitively.

Question: You showed a map of world countries with proliferation issues. Who is the preparer of that?

Speaker 1: Sharon Squassoni, from the Carnegie Foundation. It has a title like mapping the nuclear renaissance. It's well worth a look.

Question: Do your plant cost estimates include any decommissioning costs at all?

Speaker 1: No, they aren't detailed estimates. They are based on the keystone, Moody's and estimates from Florida recently. It would be good to add decommissioning, I just didn't do it for this.

Question: Do license extensions significantly increase decommissioning costs or do they have spread them out?

Speaker 1: My intuitive answer is no, the big part of the decommissioning costs occur when you irradiate the plant. The longer it's operated the easier the problem assuming the operator is continuing to collect money for the decommissioning over those kilowatt hours. Hopefully they are keeping pace with those costs.

Speaker 2.

While we are focused on nuclear, electricity overall is the lifeblood of our economy and quality of life. There is clearly a tough period coming up for the system. Further, I hope to correct some of what the first speaker meant to say. [LAUGHTER] However I don't necessarily disagree with their assessment of future scenarios. I'll be focusing on the perspective of the industry. The strength of our electricity system from a supply standpoint is diversity of technology and fuel. Nuclear is not a silver bullet either for climate change or for electricity supply. It's a diversity issue. The foundation for building the supply should be on things like conservation and efficiency.

We can't take a Washington approach of a zero sum game type of dialogue. Whether the Socolow wedge assessments are correct or not, different sources and approaches are needed to satisfy demand. The industry certainly can't build 300 gigawatts of new capacity by 2050 in this country.

The climate change debate is ongoing in Washington. Recent surveys by Deloitte and Touche of electricity customers and public utility commissioners show that 48% are very concerned about climate change. The number was 59% for the public utility commissioners. However 53% of customers were also very concerned about electricity prices. 36% said they would take a 5% increase to address climate change. 34% said they would not take an increase. If the increase was 10%, only 17% were willing to do that to address climate change.

87% of the commissioners expected at least a 5% increase next year. Only 29% thought that their customers would accept the 5%. 26% thought 10% would be accepted. 31% thought their customers wouldn't accept any increases, about the same as the customer survey numbers. The question is whether customers and regulators are ready to address a low carbon footprint and the increased costs associated with it, in the midst of rising prices overall. Nobody wants to address these two issues together, this is the big challenge.

I've heard many different presentations on climate change over the last year. If we really think climate change is a threat to our planet and way of life in the next 40 or 50 years then the adaptation option needs to get a lot more attention because mitigation is very difficult, and very unlikely. Governments will talk it, but they won't execute it very well. If the time frame is longer then we have some options, but if it's 40-50 years that's very challenging.

Let's get to nuclear. I believe our country operates the best, safest, most reliable nuclear plants in the world. Capacity factor is not a measure of safety but it is a good proxy. One can't be operating at high capacity factors if you're having safety or reliability problems. The fleet is operating at almost 92% which is really good. The first quartile in the industry is around 96% on a three year rolling average which takes into account refueling outages. That is about the theoretical best one can get. Because refueling and maintenance do need to occur.

The U.S. program is the biggest in the world by every measure. We have more units, and produce more kilowatt hours than any other program. The two next largest programs are the French and Japanese and it's bigger than both of those combined. It is just under 800 billion kilowatt hours a year. The program is very large, quite good, and operating very well currently.

Nuclear is also 70% of the U.S.'s non-emitting electricity today. This is carbon and also SOX and NOX emissions. In the last 15 years they've added the equivalent of about 25,000 megawatts to the grid by improved capacity and upgrades. This has occurred even as many plants have been closed. It's the equivalent of 25 new 1,000 megawatt plants. Companies looking at new nuclear are doing it in part because the current fleet looks so appealing. The industry is primarily focused on safety and reliability. They know that regulatory, political, and public confidence are essential to the reputation of the industry.

Let's consider capacity growth from the fifties on. The previous speaker discussed a 1980s renaissance. There wasn't really a 1980s renaissance. 1980 was one year after Three Mile Island [TMI]. The industry was not moving forward licensing new plants, they were canceling plants. TMI was not the only reason. The main reason was because of the OPEC oil embargoes, a high inflation rate, and we learned as a nation that electricity demand actually had some elasticity.

The industry finished 50 nuclear plants during the 80s. A lot of coal plants were also finished then. The electricity industry entered the 90s with a relatively robust economy and extensive base load capacity. As the Energy Policy Act passed, and the stranded cost debates were occurring, it paralyzed many companies. They didn't want to invest in anything because they were uncertain about their current stranded costs. Eventually many folks built a lot of gas. An investor could wait the longest time because build time was short, it needed cheap capital, certainly cheaper than nuclear or clean coal.

The industry didn't forecast that gas prices might reflect supply and demand, which is somewhat remarkable. They started with $2 gas and it's been up to 14 and currently it's around $11. Electricity prices go up because gas is on the margin. Now, to be honest, the high prices may help with conservation and efficiency because of price response but it is a painful way to do it. The industry built 290 GW of gas after EPAct up through around 2005. In the same period there was 14 GW of coal and around 2 GW of nuclear. The gas plants were risk free, safe, they're manufacturing plants, no problem. There were built by independent power producers who were trying to leverage the system and grow. Ultimately there was overbuild and the banks got burned on the gas. However, many couldn't get on the grid because of transmission constraints. This certainly made the investment community suspicious of alternates like clean coal and nuclear with much larger capital costs. During that period no base load was built.

What we need as a country as we go forward is base load. Companies are looking at nuclear and clean coal to do that. A lot can obviously be done in efficiency. Every company and PUC is looking at renewable portfolio standards, and mechanisms for conservation and efficiency. However just passing an RPS doesn't make it happen. It won't be easy and in the meantime companies need to bump up their base load capacity. Nuclear doesn't have some of the uncertainties coal currently has. Coal has uncertainties in climate change requirements, in sequestration, and other technical issues. The MIT crowd doesn't believe we're there yet. Nuclear has to be in the mix for base load.

However, the reality is probably that the country will build a lot more gas. The country will go slower on nuclear and coal than it should; for both political and technical reasons. Costs will count too. CERA, Cambridge Energy Research Associates, believes one trillion needs to be spent between now and 2020 on the entire electricity system. That estimate just increased from 750 billion because of commodity price increases. Renewables need new transmission. The costs are everywhere.

License renewal is a big concern for all plants. Virtually all have either gotten, filed for, or announced for license renewal. I expect all 104 plants will go through the license renewal process. It doesn't mean that they'll get granted the license. NRC may have a problem. It doesn't mean if they get a 20 year license that they'll operate for the whole 20 years. They could stop short.

Recently, South Carolina Electric and Gas and Santee Cooper announced they will build two plants with AP 1000 Westinghouse plants and the cost was $9.8 billion. That was forecast to 2019 or so with owners cost and the EPC (engineering, procurement and construction contract). The plants are expensive; $5-7 billion a plant. This requires a real look at costs because new base load will always be expensive.

Costs require a discussion of loan guarantees. Companies are not going to build a nuclear plant because there's a loan guarantee and they can walk away from it. Second, these apply to any clean technology, renewables, clean coal, or nuclear. There's 18.5 billion allocated for the nuclear plants. The loan guarantees serve a couple of purposes. The largest company has a market cap of about $60 billion. At $60 billion they're building two $7 billion projects. That's a tough lift for a company that size; financial firms have deep concerns about the percentage of risk a company like that is taking on. Certainly Exxon Mobil could build whatever they want out of their pocket change. They could team up and do partnerships. I expect that to happen in the industry.

Loan guarantees in a merchant or regulated market also help the consumer. Projects might compare 50-50 debt equity versus an 80-20. They can't get 80-20 without a loan guarantee right now. The financial community will not do it. This is primarily because of the risk of new technology. An 80-20 versus 50-50 debt equity reduces the price of electricity to the customer by three cents per kilowatt hour. From ten down to about seven because with more debt to equity ratio there is a lower return aggregate. The loan guarantee moderates the impact on the customer and helps plants get built. Loan guarantees are absolutely needed to get the first wave going. Absolutely. The industry doesn't need them after the first wave, to establish a track record of building the plants.

The new licensing process is set up to be very orderly. I disagree with the first speaker. It provides meaningful opportunity for intervention on substantive issues. The process would be even better if there were certified designs with the NRC sitting on a shelf already reviewed from a safety standpoint. A developer could go out and bank a site, come in with the license application to put the design on that site and an orderly process would ensue.

They are close to having a couple of certified designs even though they're being amended. There are three more designs coming in process as developers are filing construction and operating licenses [COLs]. The chaos is driven by the need for electricity. Companies can't wait for this to go in a nice sequence, they're doing things in parallel and that's created some disorder. During the U.S.'s first wave everybody talked standardization and it never happened. The hope is that a new wave will be based on 3-5 certified designs. Standardization is simply the right way to go. The French did it perfect but it was a lot easier. One, there's only one electricity company, one reactor supplier, and one fuel supplier. They were all owned by the government. It becomes pretty easy with a scenario like that and one can exercise discipline. The U.S. is more disciplined now. Are we as disciplined as we should be? Probably not. Because only in America could one say the industry is fully committed to standardization this time but there are five designs going forward at the same time. [LAUGHTER] However, each of the designs should stay consistent from location to location. They'll have 5 designs instead of 100 designs, so that's an improvement.

The industry is in a state of decision making and change. There are no fully ordered plants yet but there is real commitment in any case. $2 billion has been spent on license application activities, engineering, and design and procurement of long lead time items. Obviously there are options in these processes. If a developer wants a plant in 2017 they must do some procurement activity now. Certainly licensing. For certain designs other developers can buy another's slot in the queue or their forgings but developers have to get started now.

Expect to see companies form up in different partnerships. The investment community wants nuclear developers to get creative with partnership arrangements. PUCs play a major role in the decision making for these plants. They can improve certainty by allowing new partnerships to develop.

I'd like to respond to the first speaker's assertion that there's different messages for Congress and the investment community. It's the same message. The technology is proven. It's still light water reactor technology, but more advanced plants. There are no gas or sodium technologies. There's real improvements in safety and operations.

The proliferation issues are real, as are the safety issues. Most of the countries where we will see real growth don't have a regulator. The U.S. has the most effective regulator in the world. Other countries have major challenge in getting safety regulators in place, getting infrastructure. The U.S. has to play a leadership role in dealing with some of those issues, because of its experience.

Nuclear will be deployed in good countries and others that we should all worry about in terms of proliferation, safety, and reliability. We need to deploy nuclear aggressively in this country. That means 4-8 units by 2016, 2017. Second we'll need more units but only if the industry can show it can build them right. The U.S. lacks extensive experience in construction management of highly complex manufacturing, not just nuclear. It's a big job but one that the industry can step up to it.

Question: What are comparable capacity factor numbers for the Europeans and the Japanese over time. What has caused that capacity growth in the US? Some argue that restructuring and market competition did it but regulatory incentive programs started to be implemented in the 1980s too.

Speaker 2: It's hard to compare with the Europeans because they load follow. They follow load, we don't. Their capacity factor by definition would be lower than ours even though they produce a greater percentage of their domestic supply. The French capacity factors are in the 70s. The Japanese shut their units down every year for inspections so they'll be lower too.

The performance improvements started when Corbin McNeil took over PECO. He didn't like long outages and they benchmarked the Europeans. They found it wasn't rocket science to improve outages. They did more up front planning and training. They reviewed critical paths on an hourly rather than daily basis. They planned smarter and managed better and reduced outage. That drove a secondary factor. If they could run outages shorter they had to have everything done before the outage. If a project in a 120 day outage was late it didn't matter. For 18-20 day outages that couldn't happen. They were forced to pre-plan for everything and they created many improvements. They set expectations for shorter outages and the whole company culture changed. They knew they had to get smarter in a competitive environment.

Question: Corbin and PECO were driven because of the market, because his units had been disallowed from rate base. The market created those incentives for Corbin and PECO.

Second, how do the Europeans load follow with their nuclear plants? Doesn't it degrade performance? Isn't there a fear of outages?

Third, in your discussion of gas, you made the comment that there has been no base load with the gas. Was all the gas you discussed peaking units or combined cycles? My understanding is that combined cycles are supposed to be base load.

Speaker 2: The U.S. operators don't like to load follow to avoid putting the plant through transience. Now, the French do it safely and reliability. Their approach is different and it may have to do with markets. They're trying to sell their electricity and it's not all in France. They export much of it. Depending upon their export demand it's how much do they want to produce from certain plants. U.S. plants don't want to cycle the plant that way.

My discussion of gas include combined cycles. I don't think gas is a great base load capacity source. When I think base load I think coal, nuclear, hydro.

Question: Is that because of price or because of fuel?

Speaker 2: Both. It's a stupid way to use gas. Burning gas for base load electricity is a terrible waste of a much more important commodity. A power plant eats gas. It can be used more efficiently in special contexts like chemical manufacturing.

Question: Can we expect a similar cost per KW as the SCANA plants you discussed earlier?

Speaker 2: It's hard to tell. Each one is different. Transmission lines can add a lot to the owner's cost. EPC costs will be similar. One would expect suppliers to be consistent with their pricing, but other aspects will be dictated by the site.

Speaker 3.

I will discuss some of the activities of the NRC and some of my own perspectives. First, I don't think we're anywhere near the middle of a nuclear renaissance. The real nuclear renaissance happened in the 1950s when nuclear energy was developed as atomic energy. The next nuclear renaissance will be if and when we're able to develop nuclear fusion. What we're seeing right now is renewed interest in constructing nuclear power plants and that is all.

Currently, NRC anticipation is probably for about four to eight units. Those are very different from the numbers that are publicly stated for interest in new nuclear. Those are more consistent with the so-called nuclear renaissance which lead one to expect applications to be filed for 30 some units in the next several years. Those will certainly not materialize. Instead it will be 1-2 in the next several years and a few more over the decade. This is in line with the loan guarantee amounts of 18.5 billion.

The 18.5 billion was not the product of a concerted effort on the part of the industry to have more loan guarantees. It was a strong effort to provide extensive funding by Congress. It shows a certain degree of support from Congress and certainly from the administration. This is really support for a few units to start a new wave of builds. It's much more limited than a renaissance.

In the end it's not necessarily the cost of a nuclear power plant, it's the risk. This is financial but I'm going to focus a little bit on the safety risk. That is the focus of the NRC and where their expertise is. The nation must fundamentally understand what is meant by nuclear risk. What does it mean to the nation for a nuclear power plant to be safe?

There is not full understanding, nor a definition or concept that is clearly accepted by the public. These kind of discussions are needed. There is still a level of uncertainty about whether this is safe technology. This is in part because we haven't really yet defined what we mean by safe. The Nuclear Regulatory Commission has done this. In 1986 they set safety goals for plants operations in a policy statement. It provides a good definition in some ways and has weaknesses in others. There are two sets of safety definitions. The first is called a qualitative safety goal. In these the nation has some consensus. There are two aspects to this. The first says that "individual members of the public should be provided a level of protection from the consequences of nuclear power plant operation such that individuals bear no significant additional risk to life and health." Everyone can agree with that. In safety goals there's a collective element of risk and an individual element of risk. The first was the individual risk.

The second is that "societal risks to life and health from nuclear power plant operation should be comparable to or less than the risks of generating electricity by viable competing technologies, and should not be a significant addition to other societal risks." Again most can agree with this. Now, when a nuclear regulator has to issue a license that is completely useless to them. Those definitions set no standards. However, the Commission also set a quantitative health objective.

The second definition set parallels that qualitative health objective quantitatively on an individual and societal basis. It says, "the risk to an average individual in the vicinity of a nuclear power plant of prompt fatalities that might result from reactor accidents should not exceed one tenth of 1% of the sum of prompt fatality risks resulting from other accidents to which members of the US population are generally exposed." Now, the second portion is that "the risk to the population in the area near a nuclear power plant of cancer fatalities that might result from nuclear power plant operations should not exceed one tenth of 1% of the sum of cancer fatality risks resulting from all other causes."

The problem with these precise definitions is that a regulator cannot calculate the sum of cancer fatality risks from all other causes nor can they calculate the sum of prompt fatality risks resulting from other accidents to which members of the US population are generally exposed. Although they are specific and quantitative they define things that we cannot measure. The commission has generally taken these issues and come up with a more slightly modified understanding of what this means for safety.

They use two metrics. The first is the risk of core damage frequency. The only way to have an accident in the reactor is if there is a core melt. They looked at the frequency of core melts and decided the risk of that frequency of that core melt to be less than one in a million. A second metric is the larger early release frequency. Again, if there is a core melt but none of the material in the core gets released then there is little problem. The core damage frequency tries to capture the broader aspect of the risk overall to the population. How often are accidents going to happen? This gets at that individual risk. It's early releases where our infrastructure's not necessarily well geared to protect the public in an optimal way. There isn't time to do evacuations, emergency planning, or move a population.

Those are the NRC definitions but in practice there is a confusing understanding for members of the public, regulated community, and the government about how they use this information and what it means. For instance, at Vermont Yankee nuclear power plant recently there was an incident involving cooling water. Water is very important to the reactor, it keeps the reactor cool. When that water takes heat away from the machinery it's protecting the heat is released by sitting in cooling towers. They are just a way to have water evaporate and when it evaporates the heat is gone.

At Vermont Yankee two cooling towers at the facility collapsed. Now, from the NRC's perspective there was no safety issue because cooling towers are unrelated to unsafe operation at the plant, to things that would lead to core damage frequency or large early release. The event had no safety significance. There are some cooling towers at that plant that do perform a safety function and are tied into the systems that are required to operate successfully to remove heat to insure there aren't accidents. These cooling towers were not.

However, the public was appropriately outraged because this is not good operation. It doesn't lead one to believe that the plant is operating safely if these kinds of things happen. Nonetheless it underscored the fact that as a society we're not comfortable with the decisions about what is safe and what is not safe. Nuclear advocates are also working to educate the NRC about areas in which they are providing too much safety, there is too much of a requirement in place.

So again, we do not fully understand what mean by safety and this is a difficult situation. To some degree is can't be completely solved because safety is fundamentally a very difficult thing to define. It changes as societies change and as other risks in the society change. The NRC is constantly reevaluating the margin.

Another recent example is something called the pressurized thermal shock rule. The most crucial mechanism in the current fleet of operation is the reactor vessel. That's where you make the nuclear power and the fuel core is surrounded by a pressure vessel that's crucial to the safe operation. In certain accident scenarios or situations in which there is significant change in the operation of the reactor, tremendous shock and stresses on that vessel can occur. As the vessel ages and is exposed to a harsh radiation environment the material properties of the material change. The rule is a significant limitation on license renewals. The NRC has to figure out whether that material will become too brittle or behave in such a way that it can't handle these stresses. The NRC had regulations for this for a long time but recently went back using new information and better computer models and analysis. They now believe they were overly conservative in their understanding of this issue. That's good science and technical information but doesn't inform the safety question.

The safety question then is whether they would allow a change to allow longer operation and license renewals. Or do they say oh good, we've learned that the plant is safer than we thought? In this case, after a thorough review the Commission did revise the rules. So there are ways in which rules and risk and safety definitions can evolve in different ways.

A vital new element for NRC consideration is terrorism. Addressing this issue does not fall in the normal paradigm of risk analysis. They are not accidents, with random frequencies of occurrence. They occur intentionally. It's very difficult to calculate from a risk standpoint. It's pretty much impossible to say that the risk of a terrorism accident is less than the risk of an earthquake accident. The NRC has to determine whether to emphasize prevention or mitigation – how do they prioritize their resources? This is an ongoing regulatory issue for them. It's also a question of public health and safety but also the wellbeing of our economy which has tremendous impacts for health and safety in a more broad sense.

The NRC has not yet come to as broad a consensus as I would like. These kind of discussions are exactly what's necessary. That's why discussions about nuclear power are so heightened and the term nuclear renaissance is thrown around when currently they're only expecting a couple of new nuclear power plants. They didn't go away from nuclear power for 20 years in this country. There are 100 plants that have been operating for decades. The key to all this is with the regulator and their ability to create confidence with the public through their decisions.

Speaker 4.

I'm going to discuss new nuclear build from the perspective of companies developing and running nuclear plants. I am bullish on new nuclear plants in the United States. We probably need 250 new plants by around 2050. However the industry has to start with one and if they don't do one right as an industry then they won't get two, let alone 250.

I'll discuss a project being implemented by Exelon. They're investing upwards of $100 million in a project done in Victoria County, Texas. Texas has conditions favorable for new nuclear. They are experiencing about 2.5% a year of load growth. There are declining reserve margins. Current projections from ERCOT are that by 2013 they will be at equilibrium or perhaps below the 12.5% reserve margin. Texas also still has gas on the margin which means it is subject to volatile price spikes, volatile supply in the fuel. This is despite the large wind presence in the state. All the fundamentals for nuclear are there. Further, Texas is very accepting of new nuclear. Indeed folks in Texas have been asking companies why they aren't building nuclear. They need a lot of low carbon base load that is reliably delivered. Wind can do some of that in Texas, but nuclear also has a role to play. Fuel diversity, security and supply of fuel, price stability, and overall affordability are all advantages. Even though it costs a lot to build nuclear, production costs are far and away the lowest of any electricity generating source. There are environmental advantages because there is no carbon.

They have conditions at Exelon for new nuclear build. They include public acceptance, progress on resolution of the used fuel issue at Yucca Mountain, a stable regulatory environment with certainty, and the commercial viability of an advanced technology. They're looking at the passive General Electric ESPWR. The economics must work because they are building in an unregulated market. They are telling the same story to various stakeholders, whether it's Wall Street or Congress. They need certainty, to identify and mitigate risk. They want to set a standard, prove that it can be done and set a model for large scale development of new nuclear.

This should work. Much of the ground work is in place. However there are many hurdles before steel and concrete are in the ground and electricity is being produced. There's a whole group of issues around regulation and policy. The part 42 licensing process for new reactors has been streamlined. There's now a combined construction and operating license instead of being separate. These are intended to produce a single set of hearings. The issues still need to be heard fully but it's no longer a question of how many times they go through the process. This reduces uncertainty. Despite the multiple technologies, the industry is very coordinated. The Nuclear Policy Oversight Committee meets regularly. There is substantial coordination, and recognition that the mistakes of the past cannot be repeated.

Exelon's polling shows public opinion at 62% favorable for new nuclear. That number is higher in south Texas where the plant will be located because people believe it will add substantial economic benefit. Concerns for carbon have clearly helped public opinion. Regulations like EPAct and the loan guarantees also provide important support.

Note that the new licensing process has not been tested and won't be for some time even though there are applications already on file at the NRC. There is a new administration coming into office within months. The Bush administration has been very supportive of nuclear energy. That will change and no one really knows how. Developers face uncertainty at the NRC, and uncertainty in climate legislation which will affect the entire electricity industry. And certainly there is uncertainty concerning Yucca. Interim regional storage is an option. NEI is advancing it but it's still in its infancy. State regulatory issues also present uncertainty.

A state issue in Texas is water. The water issues around new nuclear and coal technology are significant. Water is not unique to the utility business. In southwest Texas there are concerns for agricultural use of water and this impacts permitting significantly. So clearly there are many uncertainties.

Cost issues are enormous. The cost for new electricity generation for everyone is going up. Wind generators, coal plants, and LNG producers are all competing for the same copper and nickel that goes in the same stainless steel to build turbines. They're all competing for the same qualified work force. And it's global competition with the hurricane recovery industry, India, China, the middle east, Brazil. Materials and qualified labor in competition everywhere.

An advantage for nuclear is once it's operational it's pretty cheap. There is a fuel cost advantage,. There are spikes in uranium, but overall it's pretty stable and there is plenty of it. Nuclear is very competitive with other low carbon base loads. Shrinking reserve margins and rising electricity prices, along with future carbon costs and gas on the margin provide a strong revenue line for the output of a nuclear power plant. Even if costs are going up the economics look good.

Different projects are going to have extensively different costs. They're very hard to compare on an apples to apples basis because some people are in a regulated environment and they have a different incentives than a merchant environment. Some include transmission, some include interest, some are in 2008 dollars, some are in 2018 dollars. It's hard to get a sense of comparative costs, other than to know that they are rising and that most of what we are seeing is estimates.

Financing continues to be a significant risk. The loan guarantee program is a way to bring private money into new nuclear. It brings certainty in and keeps the cost of capital down. Because of this there is significant interest from investment banks, hedge funds, non-nuclear energy companies, and overseas energy companies. They see opportunity.

They also see uncertainty. If a couple of plants can get built and the cost of capital can be kept down then private investment will come to new nuclear generation. There's money sitting on the sidelines waiting for it to happen. That's the principle purpose of a loan guarantee program. It tells a private lender they can take a reasonable risk looking at the economic fundamentals of the project but knowing that the significant uncertainty in initial projects is offset by the backing of the federal government. Incidentally, the owner pays a credit subsidy fee which will be in the $400 million range for the south Texas plant. The government gets revenue from the program. The loan tenure is for construction plus two cycles which means they'll be refinancing debt from the loan guarantee in the private debt markets after four years of operation. It's hard to see it as a subsidy. It's a necessary tool to bring private investment.

Let's look at infrastructure. Japan can construct a plant from first concrete to online in 39 to 42 months. That's way different than the US experience in the 80s. They use innovative techniques around work planning similar to the new approaches to plant outages. The Japanese have strong labor productivity and modularized construction techniques which speed construction time and keep cost down. That's the model for the U.S. It's primarily an issue of applying those lessons here. The labor productivity issues will be a bit different, and so will the supply chain for the U.S. context. Nonetheless, in the 80s the world built upwards of 200 to 300 nuclear power plants and there was an infrastructure there to support that.

Qualified labor is a big concern. The industry addressed this poorly in the past. Plants were hundreds of millions of dollars over budget. Some plants took ten years or more to build in the 70s and 80s. Three Mile Island (TMI) wasn't as important as poor execution and incompetence for undermining public confidence in new nuclear. TMI simply represented the overall failings of the industry. The industry did not prove that it could do this. They cannot repeat that mistake and they are very aware of this. They are addressing this at all levels.

So what is the new nuclear vision? First, look at the current fleet and maintain excellent levels of operation. Next, the whole idea of innovation and bringing new models to how they share risks is essential. The way the plants were contracted and built in the 80s is not a model that will work. Builders cannot push all the risks off to owners. There's no ratepayer backstop in Texas. If the Exelon plant goes bad, it won't be the ratepayers or the taxpayers who suffer, it'll be the Exelon shareholders and the partners who do.

That's an important difference. There are extensive partnering discussions with vendors. The whole EPC model is different because the stakeholders – vendors, contractors, partners, investors – all understand that it will not happen without risk sharing and reward sharing on the back end. They have to take advantage of the good experience and expertise that has occurred world wide. The planning has to be disciplined and so does the execution. Finally, communication at all levels will be critical to the success of a new nuclear vision. It is critical to a carbon constrained world, to economic growth, and to the control of future electricity prices.

Question: A Deutsche Bank report came out yesterday, and it noted that you need $12 in MMBTU to MPV versus $10 in all the other markets because there's no capacity market in Texas. Is that part of the reason why Texas is better in your opinion?

Speaker 4: I read it and I suspect that analysis is similar to the economic modeling for the south Texas project. I'd say their overall view is correct even if there might be differences on some of the smaller points and assumptions. Electricity prices have to be high to support new nuclear. However, forecasts for electricity prices go beyond what is needed to support new nuclear. This is in large part because of the gas driver and the carbon driver.

Who can predict forward power prices? It's a very difficult thing to do for five years, let alone 20 years. A lot rides on the power price forecast but the fundamentals also demonstrate that carbon cost is going to be part of this – the fundamentals are there.

Question: What about new builds in restructured states or RTOs. It's different in Illinois and Pennsylvania. What are the issues in states like that?

Speaker 4: I look at it principally from a merchant perspective. In restructured states there should be no ratepayer backstop. There's no commission or rate case that determines costs and returns. In any market environment a nuclear merchant developer has to determine what the cost to build will be and determine the NPV [net present value] and an internal rate of return valuation that is satisfactory to the board and shareholders?

There's many complicated inputs for such a developer. I don't have much expertise in the regulated environment. The only issue here is that the regulator is obviously much more involved. The decision or the economics on the build decision is a function of what the utility and the regulator conclude together.

You see this with Dominion in Virginia and FPL in Florida. The Florida commission is willing to support electricity price increases necessary to fund new nuclear development in Florida. They believe it's necessary. That calculus is fundamentally different because it puts a premium on the rate case and introduces traditional regulatory issues. What if costs exceed expectations and will they reopen hearings or a stranded cost type issues. In an unregulated market the discussion centers around more traditional investment parameters planning, mitigating risks, and producing electricity with a profitable rate of return at a cost that's low enough for consumers in that state. The commonalities are costs, regulatory stability, public acceptance, and used fuel continues to be a concern.

One other note. Companies will be competing for a limited amount of loan guarantee dollars. So for instance, brown field versus green field. The Exelon Texas project is a green field site and most others are brown fields. This brings up issues concerning spent fuel. The loan program will need to determine if one is preferable to another to prioritize which sites get guarantees. Similarly for a regulated or unregulated environment. Does one do more for consumers than the other. Exelon would argue they should get the loans because they are developing in a restructured environment and that is better for consumers. Dominion would argue the opposite.

Speaker 1: Let me say the same thing but in a different way. There are three pockets out there: private sector capital, customers, and taxpayers. If one wants to build a nuclear plant you can't look to unaided capital to finance it. So you're going to be looking to either the customers or the taxpayers to help out. In a regulated market the potential to align the commission with the project through preapproval, through construction work in progress, via the legislature through statutory change that eliminates the used and useful disallowance. There is greater assurance of capital recovery from the customer. The loan guarantee is nice too but it may not be absolutely essential. In the restructured markets, Texas, Illinois, Pennsylvania, New York, the customers cannot be brought in to support the project. The taxpayer is the backstop and the loan guarantees are more essential in competitive states.

There is also a hybrid. The SCANA and the south Texas projects both involve a large public power entity. Those projects can achieve substantially lower costs of capital because of the public entity's ability to debt finance. It's a kind of de facto guarantee for a big chunk of the project.

Speaker 2: The three projects that seem to be the faster movers all have those characteristics. NRG in south Texas, SCANA, or Southern. They all have municipalities or rural electrics with them.

Just a comment on loan guarantees. The nation has $60-70 billion of loan guarantees outstanding from the ExIm Bank for projects overseas. If we can do that for projects overseas why not for projects here? Are our contractors able to build better overseas or is the political process better overseas so there's less risk? Are the commercial terms better overseas? Further, the loan guarantees get paid for. There's no taxpayer money. If a project gets a loan guarantee from the government they pay a credit subsidy fee. The fee is determined by the risk of the project, similar to a commercial banks assessment of risk. These fees go into the loan program and reduce taxpayer costs.

New builds will be very different from the last round of builds because everybody's looking at risk sharing. How much should the contractor take? How does one hedge risks on commodities? They are improving the model. It isn't the old way. Similarly the credit subsidy fee lets the government weigh the probability of failure. They get paid for it. Real money up front from the entity getting the loan guarantee.

Speaker 4: One additional thought. Merchant developers are not looking to sell it all on the open market. They are actively looking at partners, PPA counter parties, at hedging going forward. All these things reduce risk as well.

Speaker 3: There are some issues in restructured markets. There are prohibitions on communication between transmission and generation. Seabrook recently did a power uprate. This put them above their single large failure contingency for the New England ISO. The ISO was repeatedly asking Seabrook to power down. In the U.S., we don't like plants to load follow in this country. This was a failure of communication between the transmission and generation side about the acceptable parameters for the power uprate. Seabrook received a power uprate that they could not use from the transmission and reliability side of the house.

This has occurred in other situations. New reliability orders, and restructuring implementation has created a much greater need for communication. FERC came out with an order to lift prohibitions on communication between transmission and generation when it came to nuclear safety issues and nuclear operations. Regulators and the industry is focusing on these issues, especially with new construction.

Transmission development and nuclear both have similarly long time scales for planning and development. There needs to be a lot of communication on these development issues or else the capacity of any new nuclear may end up being severely restricted by inadequate transmission.

Question: Some state regulators have concerns about lack of transparency in nuclear operations. The classic example being INPO [Institute for Nuclear Power Operations] although it did bring a lot of positive peer pressure on companies to perform better. An additional reason for increased productivity would have to include peer review. The INPO story was a national secret. NRC couldn't discuss it, state regulators weren't allowed access to any information about plant operations. Some citizen participation groups have expressed concern about new NRC licensing provisions and the loss of public participation in the process. Can the industry be more transparent than previous times? The lack of transparency contributed a lot to the public's attitude about nuclear power in the past.

Speaker: INPO was formed after the Three Mile Island accident. It was created by Bill Lee, former chairman of Duke. It's an institute that strives for strong performance in the nuclear power industry. It's not a regulator. They do plant evaluations every two years at every plant and ranks plants. The results go to plant management and also to the chief executive officers. They get confidential information from the people at the plant. They do extensive interviews. They have contributed extensively to improved operations, with a focus on safe operation of the plant from a core standpoint, not necessarily outages. They do try to keep their evaluation results and discussions private. This is valuable because it means they get complete access.

INPO also runs a closed door CEO conference every year. One feature is that CEOs have to comment on the review of their facilities. If they have not done well they have to explain why. And any of you that have had the pleasure of doing something like that with your own peers can imagine the pressure that's on the individual to stand up and explain why they are embarrassing the industry and creating credibility problems. This is an extremely effective process. However, it is effective in large part because it is not transparent.

Let's consider the NRC. They moved to a reactor oversight process that is incredibly transparent about six years ago. It's on their web, one can look at every plant, and there's a pretty simple color scheme for the NRC's assessment of how that plant is performing. There are many performance indicators. You can drill down to the local area or state and get a complete assessment. So the NRC is very transparent but INPO is less so. I'd argue that INPO's value is greater in the way they do business. They probably need to communicate better what they do and why they do it the way they do it so there isn't a trust issue. But I would rather keep their effectiveness high and try and deal with the perception issue than potentially decrease their effectiveness to make it seem like they're more transparent.

Speaker 3: INPO is not a regulatory body, it is an industry organization that self regulates. Their role is different from NRC's. There is still some difficulty with issues of transparency in operation. Not necessarily with the public but sometimes with the regulator. For the public there's two important points. One is about availability of information. The NRC does a good job of providing information. But transparency also involves accessibility of information and to that extent they do a terrible job. An average member of the public cannot access an inspection report and have a good understanding of what that inspection report is talking about. That is an important difference, and an area where they have to continue to work. If they flood the public with data and information but no means to process it then they are no better off.

The real challenge right now is in the area of security. In this area, information is more restricted than in the safety area and that's of necessity. However, they have to continue to reevaluate because if they don't provide information for the public to be able to participate meaningfully in their processes then they haven't really achieved the ultimate goals of being a public agency and ensuring public confidence. The two areas are information accessibility and security.

Finally, some stakeholders are not allowed to participate in the proceedings because they do not meet a series of procedural thresholds that have been established. So all of those things ultimately lead to a reduction in that transparency.

Speaker 1: There are real concerns about information in state regulatory proceedings than can be sheltered under the rubric of commercial sensitivity. In the Carolinas, Duke Power is on the verge of getting the go ahead to both states for the William States Lee units without ever furnishing a public cost estimate. The public has no idea how much the plants will cost and how much the rate impact will be and yet the commission will grant a preliminary need determination without ever making that information public. That is unreasonable.

The second is the NRC's own proceedings, and I don't mean the COL. Rather it has to do with their practices in hearings. It is now very difficult to get the right to cross examine. One has to ask questions through the panel chair. It's very restrictive. It's also very hard to get discovery or getting contentions admitted. When the public comes up against this new process it isn't just that it's complex and technical and impenetrable. It's that it's designed to wall out the public from being able to raise the kinds of concerns they have. It's a serious problem. When the public appeals or takes up an issue from these proceedings, the Commission rarely intervenes on the side of the public. Instead the NRC's focus seems to be all about keeping the trains on time.

Question: This panel is running late, can one even do a panel on nuclear power without overruns? [LAUGHTER] The SCANA plants, if they come in at 2,200 megawatts at $9.8 billion, it's $4,000 an installed kilowatt. This isn't an absolute decision about whether to do nuclear, it's a relative decision. These prices are similar to pricey IGCCs, or concentrating solar with storage. At those prices there are other price similar options. If one makes neutral assumptions about loan guarantees or politics, how does nuclear stack up against competing fossil and renewable technologies on a cost basis alone? Second, who does one trust for these kind of analyses? Where are the numbers that a state regulator ought to be looking to when they're trying to decide that question of the pure economics?

Speaker 4: The $4,000 a kilowatt is probably lower in the actual contract. It's hard to know what goes into the dollar per kilowatt calculation on an overnight cost basis versus some of the other costs and in what year. A lot of companies believe that at $4,000 a kilowatt nuclear is very competitive. Wind and solar don't come in that low. LNG has projections of $12-14 per unit cost for fuel which puts it on par with nuclear or maybe slightly worse.

The analytics of companies looking at this certainly consider other technologies. They also consider that gas sets the price on margin and also make a reasonable bet that carbon is going to be a part of the equation. With carbon in the equation these plants will be doable. The big question is what the price of carbon will be - $ 12, or 25 or 45.

The cost and economics of wind needs to be considered differently. Its' price is driven in large part by the carbon issue but also by the RPS standards that states have adopted. Nuclear will be cost competitive even at those dollar per kilowatt prices and probably is more cost competitive than the current alternatives out there for base load power.

Speaker: The $4,000 a kilowatt is probably conservative. It's based on having a big public power system owning a large chunk. The two Florida utilities have put in higher estimates. There's a question of how much of that is transmission. I believe they're closer to 6,000 to 6,500 even without the transmission. Moody's did a study that expressed nuclear skepticism last fall that estimated 5-6 thousand.

Second, the competition is more complicated than just a base load calculation. Wind by itself is not base load. When one thinks about wind and gas together then one should redefine the notions of base load to take into account renewable economics. Wind does well competing against those higher prices.

Finally, the competition in a carbon scenario doesn't just come from other fuel sources. It's not just base load electric, it's carbon removal. For that market one has to factor in efficiency, what can be done with vehicles, what can be done with buildings, what can be done with forest practices. The competition is a much broader playing field. It's unclear who the winners are in that much more complicated market.

Question: Let's consider the question of safety. One way to think about the problem would be that major accidents will be rare and when they happen they won't be so bad and society could live with the consequences on average and that's OK.

On the other hand I'm reminded of the comments of a senior executive officer from General Public Utility six months after the TMI accident. He said that the industry always said these plants were safe. What that meant was that an accident like TMI would not happen. Those are two different mindsets.

The concern here for a plant operator is that they have to worry about more than the operation of their own nuclear plant. They also have to worry about the operation of a whole bunch of other nuclear plants. If there's a major accident then the public reaction will be to shut down all kinds of other plants that have a similar technology. If one fails then the entire industry is in trouble.

Speaker 3: The public is certainly in the mode where safety means no accidents. That's certainly not what the commission believes and has established in its regulatory infrastructure and analysis. The very fact that they have an emergency preparedness program indicates that they anticipate the potential for accidents. There are certain accident conditions that they acknowledge could happen. They have to address those scenarios.

The potential for accidents is the more accurate reality and the Commission needs to help the public understand that. It's a simple fact that one can't control everything. Mistakes may happen. It doesn't necessarily mean that the consequences will be horrible. The Commission operates on the assumption that they have enough systems in place to ensure that public health and safety will continue to be protected.

It's even more refined than safety means no accidents. Safety means no adverse behavior or incidents at a facility. That is the public threshold. The incident at Vermont Yankee discussed earlier is a perfect example of that. The reaction from the industry was very strong and they also expressed that those incidents were unacceptable.

However there is still the mixed message that safety means never making mistakes. That is an impossible threshold for a regulator. Even the NRC's formal definitions don't use a 0% chance of risk. If the country gets to a point with 250-500 plants then we're looking at accidents occurring with a frequency.

And I don't know that people fully appreciate that and are really, the public is really going to be, at this point say that they would be accepting of that kind of a scenario. There is still very much this impression that we'll build all these extra plants but that won't inherently increase the risk. Well, it will because you've got a lot more plants, probability wise you have a likelihood, an increase in the likelihood of accidents. And so but I don't think that's what people envision when they see that. So there is still very much that sense that an accident is a real, real problem, which I mean it should be, it's not a bad thing, but that that is how we define safety and it applies and of course we don't regulate globally and that becomes a real, real challenge.

Speaker: Accidents are always an elephant in the room for the nuclear industry. Three Mile Island involved a lot of technical arrogance in the industry. GPU made a whole bunch of operational mistakes and the system did protect the public after the fact. It ruined GPU. The industry didn't treat operational safety with anywhere near the rigor they treated design safety. TMI, in a very painful way, made plants in the western world dramatically safer. There's extensive training and operators spend more time in simulators every year than any airline pilot. Every plant has a simulator.

TMI was actually an important safety enhancement event. Very bad from a public confidence standpoint, and hurt the industry in terms of new builds but very good in terms of comprehensively improving operational safety in the industry.

Standardized plants have some issues. If one fails, the rest all look bad. Plant increases are also important. The more plants built the more diligent they have to be. However, from a standardization standpoint if one plant has a problem then the fix gets to be applied to all of the standardized plants in the fleet. NRC would also certainly want to see whether that problem is a generic problem that could affect the continued operation of that family of plants.

TMI created an incentive for operating experience across the industry to be shared completely. Even between competitors. It's a very unforgiving technology. The industry has to maintain operating levels very highly, even if no new builds come on line. They're operating so well that small events become big deals. They need to do a better job of communicating. They won't ever get total buy-in from the public but a better understanding of the regulation and the emergency planning process would help a lot.

Question: The panel has discussed the benefits of nuclear power, current federal support but also financial and personnel constraints. Commodities are dear right now so there's only 5-6 potential projects that are realistic in the near term. There's potentially a scarcity of this valuable resource. Texas was discussed in terms of its load growth, positive regulatory environment, and public acceptance. What should other regions be doing and what are the barriers they face?

Speaker: The barriers are largely the same across regions and countries. The differences lie in what RTO one is in. ERCOT is different than anywhere else, frankly. Their transmission is not a part of cost for a developer. They are recovered by ERCOT via transmission rates. That's a fundamental difference for cost estimates.

However, after that the hurdles are all very similar. For instance in the southeast and other places, coal plants are getting cancelled. The co-ops, munis, and utilities cannot meet load, whether it's for carbon reasons or whatever. What are they going to do? Nuclear is now being considered in those areas. The calculus is the same in those areas. What are the alternatives, what are the cost differentials, how will the public accept it and what is the best to provide safe, reliable, around the clock power if you're looking at base load to the customers? Costs, ROI [return on investment], financing, siting, storage, all have to be considered.

The big question is what are the country's long term energy needs, and how will we make decisions among technologies all of which are costly. It's hard to nail down costs and compare them and also consider public safety and supply and costs simultaneously. That's the big overall hurdle.

Speaker: The level of public confidence in the industry divides the country regionally. There are stark differences in different regions. California still has a moratorium on new nuclear construction. New York has a re-licensing proceeding for one of the power plants there and there's strong opposition to it from most if not all of the state wide elected officials and other local officials. It's very different. Most of the difference is in attitudes towards safety and risk.

NRC's underlying statute is a broad hearing requirement. It basically says anybody's who's got an interest in the outcome of their decisions is entitled to a hearing in front of the commission. It's a broad authority that's been narrowed by very sophisticated attorneys and technical experts. In 30 days stakeholders have to analyze everything that's wrong with a license application that may have taken five years to develop. The public doesn't get buy-in in that situation. The northeast has great sensitivity to that more than other areas in the country.

48% of the public aren't supportive nationally. Whether it's legitimate or not that's there. The perception is still a problem. Further, one accident and the public will go from 60% supportive to 90% in opposition. That shouldn't be the situation.

Speaker: An educated public is an accepting public and that's fundamental. A lengthy regulatory process with multiple hearings is not the way to educate the public because it creates uncertainty for developers and raises prices. Instead, the industry needs to communicate the importance of this power source for innovation, for iPods, for electric cars and for reducing carbon. Nuclear happens to be one way, it's not the only way. The industry needs to engage in a more productive dialogue with the public but not in a hearings setting where it will inject uncertainty and raise costs.

We also need to talk factually. The emotion still runs high in nuclear power. The debate needs to be policy focused and the more emotion we take out of it the better.

Speaker: There is a myth that public involvement in the NRC licensing process delayed the construction of nuclear power plants in the last round of builds. It's just not true. The hearings go on while the plant is being built or now before it's being built. However, the NRC has processes that allow all kinds of work to be done while hearings continue. The hearings may or may not be valuable. They're expensive in terms of lawyers' fees but those are trivial in relation to the billions we're talking. However, the hearings were not a significant source of licensing delay last time. Allowing the public into them wouldn't be a significant source of licensing delay this time either.

Speaker: Public participation does not equal a lengthier process. The process is something the NRC can control. They need a process that ensures public participation. Further, it's a legal right so the more they restrict that right the more they potentially create uncertainty in the process. The closer they are to eliminating that hearing right the more likely they will be winding up in federal court. That is where the most uncertainties exist and where things take the longest, not in the NRC hearings. If they are so narrowly defining this hearing process they put themselves in a position for more legal challenges. That is where the uncertainty comes in and where the challenges really are.

The NRC has a responsibility to have a timely, effective, and reasonable process but they also have a requirement to have a public hearing process. Both of those things must co-exist. Restricting the public's participation has the effect of making the public in many areas more adverse to the process, less trusting of the regulator and having less buy-in to the ultimate outcome. That is occurring with opposition to the re-licensing of Indian Point in New York.

Session Two.
Market Power Monitoring and Mitigation in a World of Financial Transactions

Exercise of horizontal (generation) market power requires both the ability and incentive to engage in conduct whose objective is to raise market prices. FERC uses screening tools that consider a supplier's owned-generation as well as physical commitments to supply power to native load or third-parties. There are transactional arrangements other than "traditional" physical load-serving or power sales obligations or transactions that can reduce supplier incentives to exercise market power.

These include various forms of "financial" transactions, which do not physically transfer control over generation, but may nonetheless eliminate the owner's incentive to raise market prices. Financial transactions, or hedges, have become an important tool in many of the regions with transparent markets. Generation-owning market-participants with load-serving obligations have less need to enter into physical commitments and may rely instead on financial instruments to manage risk and normal price volatility. When financial commitments are not considered on the same basis as physical load obligations, FERC guidelines for market-based rate sellers may over- or under-estimate. How large might be the error? What guidelines would provide a better estimate of market power? How could improved procedures be implemented?

Speaker 1.

I'm going to focus on issues within PJM. The internal market monitoring unit at PJM will be spinning off as a separate company following a FERC settlement. They'll continue to be the market monitor for PJM but as an external organization.

I want to take a fairly high level approach to this topic. Competition in wholesale power markets is not a laissez faire model, it's a tool of regulation. Perfect competition is a tool or goal to create the most efficient prices. This requires clear market power rules with effective mitigation. FERC wants competition so perfect it would make an economist cry. It's my favorite line.

There are two basic approaches to market power. One is the market based rates approach of FERC and the other is the more direct mitigation rules in PJM. FERC's market based rates define a competitive participant but they do it for a fairly lengthy period of time. They use historical data and snapshots. It's far from representing the current reality that exists during the three year period of market based rates they look at. It's a test that is applicable to vertically integrated utilities outside organized markets. It's much less applicable to organized markets with active market power mitigation rules as well as competition, although I understand that it is still applicable formally.

Alternately, in PJM's energy market, they use a three pivotal supplier test. It's simply a market structure test that defines whether a local market is competitive. It does it in real time using the same data that operators see. The test analyzes a real demand curve to resolve a constraint, looks at a real short run supply curve that operators have available. It evaluates the ownership of that supply curve and whether structural concentration is enough that mitigation is necessary.

The test is based on the same logic as FERC's market based test but it's done in real time, dynamically. It reflects real market data on an ongoing basis in a way that the FERC approach can't do. The existence of strong mitigation rules in PJM and other organized markets should serve to supplant the market based rate test. However, having a market based rate test in addition to the mitigation rules creates too many analytical difficulties. They're going to get more complicated because the test is not addressing current market reality.

In PJM mitigation gets talked about a lot but it doesn't actually occur very often. Obviously it matters to those units and companies who are mitigated. Nevertheless it happens infrequently to a relatively small number of units. Finally, PJM also analyzes actual behaviors of units. Mitigation doesn't occur if an owner is not attempting to exercise market power.

Market structure tests are not a test of incentives. This panel is focused on whether regulators should look at incentives in addition to structure. The two tests of the efficacy of a market structure test are whether one mitigates with no market power or doesn't mitigate when there is market power. The cost of mitigating when there is no market power is very small, if nonexistent. However, the cost of not mitigating when there is market power is relatively high. Potential over-mitigation results in competitive behavior. If there really was a competitive market, that's the behavior one would see. Most of the hours in PJM without any mitigation, that's exactly the way everyone behaves. It's the way they behave because that's the rational way to behave under competitive circumstances. This is the fundamental assumption that PJM operates under.

Their market structure test is based on gross position. They look at total ownership of the assets in real time and do not account for net position. This simply means accounting for various obligations. For example a generation owner may be obligated to sell every megawatt hour or many megawatt hours to its load in an integrated company, or be obligated to sell it via bilateral contract, may have taken a follow position that takes away any incentive to raise the price. There are many ways that physical positions can be affected by explicit bilateral contracts, participation in forward markets and by regulatory arrangement. Net position is an attempt to measure incentives and it's difficult, if not impossible to do. There's certainly no sensible or practical ways to do it in real time.

The mitigator would have to know it on a dynamic basis. Sometimes multiple marginal units set the price in five minute intervals. They would have to know what the entire position was for each unit, and for each owner. Not just something in a contract, or a forward position but the dynamic status of each trader working for that company and their net position in that five minute interval, or an hour interval. It's impossible to do. Even management itself doesn't have that kind of information.

The goal of the net position analysis is to better reflect incentives. Incentives are more complicated than simply looking at net positions. One cannot capture incentives by looking at net position. Ultimately, the goal is to ensure competitive outcomes. Even in markets which are sometimes structurally not competitive it's still possible to have competitive outcomes. It's possible to hold them in one's head at the same time and not have your head explode.

So the monitor should not be too worried about over mitigating. The second concern is whether a company's positions in parallel markets, other financial positions, could mean that PJM's structural test isn't working properly? Somehow they're under mitigating, or missing market power. Can non-physical positions provide an incentive and ability to exercise market power in organized markets like PJM? I don't think so. Market power in PJM markets depends on the ownership of actual units. It would be exercised via offers of actual units in the day ahead of real time markets. There are virtual offers, INCs and DECs, but they occur in a context where there's a must offer requirement for the real assets. The day ahead market on an aggregate basis is always long. It's very difficult to exercise market power using INCs and DECs but they look at them explicitly in any case.

There are also more complex strategies for exercising market power and PJM may not have considered all of them. Nonetheless, financial transactions in other markets should not make that problem worse. For instance, the rule that addresses the ability to use virtual offers to make FTR positions more valuable was addressed by PJM. To make this work, market monitors need accurate and complete information on ownership including joint ownership and affiliate relationships. There have been issues recently with affiliate relationships and credit. It's also a question whether they need complete information on positions in related markets like ICE or NYMEX.

A combination of things is needed. Comprehensive market power rules including in PJM the must offer rule which is critical for providing the basic structure into which people are offering. One offer per day, combined with a robust structural test for market power provides an answer. That is adequate to ensure that markets will have competitive outcomes. In addition they have to look directly at the outcomes of markets. They can tell directly by looking at offers and behavior whether market power is being exercised.

In addition they need clear scarcity pricing rules. When the markets are tight having high offers can look like market power but in fact it's just competitive offers in a tight market. They need explicit rules for governing that so they can have scarcity pricing when needed and it's not confounded with market power.

Further, to make clear evaluation possible it's necessary that markets like PJM's have clear robust credit policy rules. These must be fair to all but properly reflect the risk that participants are imposing on the markets.

To sum up, improved transparency across all markets provides a benefit but the simple existence of financial positions or physical assets themselves do not create the ability to exercise market power in PJM markets, not the incentives. They certainly do affect the incentives. It's important that they understand the incentives as clearly as they can.

Question: What data does PJM actually have today regarding transactions and related markets. Where do they stand in terms of that?

Speaker 1: One part are the surrounding markets. They have to manage interactions between PJM, MISO, New York or NEISO. They have to analyze abilities to exercise market power at the seams because of inadequate coordination. That's one kind of external market. Second is routine access to ICE, to NYMEX, to over the counter bilateral markets. Currently, they have only what's commercially available. There's no special access. They have the authority to ask participants to provide it but no ongoing access.

Question: What is the biggest hole in terms of that data for their ability to assess the net position interest that you discussed?

Speaker 1: It's not necessary for them to understand everyone's net position. They'd have to know everything about the books of every company virtually in real time. Not only ICE and NYMEX but all the bilaterals; everything. It's not realistic, they couldn't handle it even if it were available, and it's probably impossible for the companies to provide.

Speaker 2.

I will go into some detail on the market power test, how manage their positions and how that ought to affect how FERC implements or administers these tests. I'll briefly summarize the most important, the market share test, and then talk a little bit about hedging options that market based rate sellers have. Finally, I'll look at some suggestions for going forward.

FERC approaches the market power test via the market share test and the pivotal supplier test. A company that passes those can sell at market based rates. If they fail they have to do the delivered price test, which looks more at the economic deliverability of capacity in different time frames. If they fail that then the company can demonstrate why they shouldn't have to go to the default. For instance, one reason might be RTO mitigation schemes like PJM's. If that doesn't work then they are subject to cost based rates.

The market share test identifies all of a company's generation and determines the extent to which their capacity is committed to native load. There's some other pieces to address if the generation is tied up in operating reserves, outages are taken into account, long term firm sales commitments. It also takes into account the generation that is deliverable on a company's firm transmission from external sources into the organized market's area.

Position management as conceived of by FERC doesn't make sense and doesn't align with what most sellers are doing. Further, as the previous speaker said, administering this area is too difficult. PJM is responsible for commitment of the generation resources. Their objective is to match the generation to the load. To the extent that PJM commits a party's resources that party ends up with a net position in the pool. They will be either net short or net long. Selling entities want to manage the price risk associated with net short or long. The question for a generator that wants market based rates every day and in every time bucket is, to what extent do they want their generation position to be committed at the spot price?

Major sellers will have a major proportion of their position in the market hedged. However, if they have an a good percentage of their supply to serve native load in some parts of their region they can't do that. What are their other options? First, they can sell the traditional physical load following product to their utilities but also to municipals and co-ops or other POLR entities. There are some limitations on that but that is one option.

Second, they can sell physical fixed megawatt amounts to the whole panoply of entities that are in the market. This is where the issue is most relevant. This includes sales to pure power marketers, investment and commercial banks.

Third they can enter into pure swaps, where they do a fix for float and hedge their position. They pay a fixed price to get somebody to take their floating price risk on the load. It's the equivalent of a purely physical sell.

Finally, the fourth option is to enter into dirty hedges. A company that wants to hedge the price risk of one product and there's another product where the correlation between the two prices is sufficiently strong they can hedge in that product.

Why would they want to do that? If they're trying to hedge in out years some markets are more liquid than others. The natural gas market is highly liquid, and there isn't as much of a market for power in the out years like 2011, 2012. So a company can do things that are equivalent to selling power if they don't like the price or they're concerned about the liquidity for that reason. Instead of selling power they can buy NYMEX contracts or buy gas bilaterally. So NYMEX contracts for gas because there's a strong correlation between gas and power right now. The reason it's a dirty hedge is that if their expectation about that relationship is off then the hedge becomes dirtier and they're much more exposed to price risk. Typically what a company would do as they get closer to the time of delivery they would get out of the gas hedge and then sell power. They want to be hedged in the product that they're primarily concerned about. This is just the tip of a big iceberg. Most selling companies have several people that do this full time, they become hedge shops. They spend most of their time figuring out the best way to minimize the price risk associated with the portfolio.

The effect of these different methods is essentially the same. All of the options create the same financial incentives to perform, capacity is committed and there's no incentive to withhold. But they are far beyond service to native load. These tests grew up with the integrated regulated utility in mind. That is still the case in many places. Those utilities do what PJM does but typically all the regulator has to do is look at cost and projections of the load. The utility will commit the resources and then just sell out whatever's left. In that context the test makes a lot more sense than it does in a dynamic market like PJM where all these other activities are occurring.

Hedging decisions focus on value at risk tolerance, cash flow requirements, earnings objectives, volatility of the earnings, credit rating cost of credit. A riskier portfolio will certainly have an effect on credit rating.

Let's look at physical and financial equivalence. They are more or less identical. The purely financial swap is just an exchange of payment streams. One party will pay the fixed price and the other party is a floating price. However it ends up at the end of the month one party or the other pays. The equivalent transaction in an organized market like PJM is a sale at some pricing point, typically a liquid hub like the PJM western hub which is a set of price nodes on the PJM system that encourage liquidity. When this is done physically in PJM nothing physical is actually changing. They're just transferring the right to claim the energy that is generated from one party to the other. There's a PJM settlement account and if company A sells 50 megawatts their account gets debited and the buyer's account is credited and there's a bilateral payment stream from the fixed price payer to the seller and it's all accounted for.

This just illustrates that physical transactions leaves out a big piece of what actually goes on in the market. This is more important now because the hedge funds and investment banks are much more comfortable trading the financial instruments. They don't want to get involved in PJM or deal with some of the financial risks associated with that. An entity has operating reserve risk depending on whether they have a physical position in the pool. There are many more financial deals out there than physical, this has changed a great deal in the last few years.

There are other factors that determine how a company will go forward. Which partners, what are their comfort ranges, what enabling agreements are set up? There are credit issues associated some of these. Swapping is less of a credit requirement because it doesn’t settle until it settles. There is less accounts receivable [AR] payable exposure whereas in a physical transaction at PJM, as soon as one has transferred power to PJM an obligation to be paid attaches immediately but the bilateral payment stream under the standard enabling agreement doesn’t show up until 20 days after the end of the following month. This creates 50 days of AR that builds up if you’re a seller. This is one more factor that affects a companies decisions process for which hedging mechanisms they use.

Here’s a recent example. In Illinois this past year after the POLR [provider of last resort] auctions went away, there was a one year RFP that ComEd ran to serve its load and at the same time Ameren, the other major utility in Illinois was doing the same thing. Neither company went out for a full load following product. In the case of ComEd it was physical blocks of power in some of the standard time buckets. The five by 16 which is five days, 16 peak hours and the off peak periods. Ameren had the same time buckets but they did purely financial swaps. They went to pay the MISO and to hedge that risk for the benefit of themselves and their ratepayers they used purely financial transactions, not anything physical. It’s an effective strategy.

If there are tests that look at commitment from FERC’s order 697 then they need to acknowledge the difficulty of trying to measure this in isolation at one point in time. They need to design a proxy to identify the sales going to entities that have won auction load. This is publicly available New Jersey or in PP&L service territory. They need proxies if this is the way to evaluate market power.

The generators and PJM are getting paid a whole lot for capacity. They have a requirement to bid into the day ahead market which ensures they want to perform in the real time market, that’s the most natural hedge. If they don’t perform the way that the capacity market in PJM works, they get dinged to the extent that there are outages. Every planned outage is approved and coordinated by PJM. It is almost impossible to play a game with that. PJM’s market monitoring ensures that these markets are competitive in real time and they are successful. If the market share test is going to continue then they need to recognize many of the non traditional entities do different things to hedge.

Speaker 3.

I agree with most of what’s been said by the previous speakers, although the statement that the cost of mitigating is low, the cost of not mitigating is high requires more definition. Over mitigating the market has costs including the failure to send good price signals to incentivize investment. It also affects true demand response and customer response to high prices.

The differences between the PJM and the FERC test are important. FERC looks in a static, non dynamic fashion and PJM looks in a very dynamic fashion.

There are two biases in the panel description that I want to highlight. The first is that financial transactions reduce or increase incentives to exercise market power. Second, that the only manner in which one might exercise market power would be to raise prices. If a company has certain financial positions and physical market power they may actually lower market prices to better a financial position and that will also have a deleterious effect on competition.

Finally with respect to the panel description it discusses incentives but not really market share. There is an underlying tension however. It’s not the same if the incentive to exercise market power is partially neutralized versus being told to automatically drop market share.

Let's consider basic economics first. If a supplier is in a financial transaction that places it in the same position it would have been if it had sold all of its capacity at a fixed price then they do not have an incentive to exercise market power.

For example if a 10,000 megawatt supplier enters into a contract for differences [CFD] for 10,000 megawatts with a particular load, they have no economic incentive to exercise market power. To the extent it raises prices the super competitive margins would go right back to the customer. In the real world it's rare that a supplier would sell all of its capacity in a financial transaction of. If a supplier has sold or hedged all capacity there's no incentive. Or if you had a situation where a supplier was also responsible for load serving obligations and was a net purchaser or a net hedge purchaser to the extent it had market price risk to serve its load that supplier would have no incentive to exercise market power, to raise market prices as well.

However, if a vertically integrated entity has surplus capacity? If the supplier has additional capacity then there are remaining residual incentives to exercise market power. First imagine a supplier with 15,000 megawatts serving a 10,000 megawatts load. They have 5,000 megawatts of physical supply left over. Alternately they might have a CFD for 10,000 MW. The CFD would naturalize the incentives for the 10,000 megawatts but not the remaining 5,000 megawatts. The question is whether one should equate that 10,000 megawatt financial transaction with a forward commitment to serve load? This is a critical question.

The supplier could earn a competitive return on the remaining 5,000 megawatts of capacity. The supplier can engage in different practices with respect to its physical supply. If they deliver physically they have 5,000 megawatts left and if they use a CFD they have 15,000 megawatts still to schedule and bid in the physical market.

There are other questions about the premise that a financial transaction is the equivalent of a physical transaction. Should all other suppliers and financial transactions also be deducted from their available capacity shares? If so the denominator's shrinking. So a company enters a financial transaction, commits 5,000 megawatts through financial transactions so drop their market share by 5,000? What's in the denominator? How does the market monitor get the information on all of the other competing suppliers' financial transactions when they're not in that market monitor's jurisdiction? This issue has to be addressed.

It's not wrong to consider a financial transaction as mitigating the incentive to exercise market. Nor is it inappropriate to reduce market shares by some amount of forward financial transactions. Rather, there are complicated issues even under a more static FERC test, let alone an hourly or dispatch interval test, that need to be considered.

In some cases, financial transactions can create the incentive to exercise market power. If a physically dominant supplier can raise prices via market power it will earn a super competitive return on its energy sales. If it also has acquired FTR [financial transmission right] positions, it can use its market power to acquire additional returns through the congestion rents that it causes. There are now three FTR like products: FTRs, TCCs [transmission congestion contracts] and CRRs [congestion revenue rights].

Financial transactions won't necessarily ameliorate the incentives to exercise market power. It can be a two way street. A supplier can use market power to lower prices when it has a financial transaction that provides extreme profits for doing so. There are currently two cases pending before FERC. In Energy Trading Partners [ETP], FERC stated, "when a firm uses some combination of market power and trading activity against its economic interest in one market in order to benefit its position in another market by artificially moving the market price the firm likely crosses the line into the realm of manipulation." FERC went on to discuss how using market power to lower prices in order to benefit a derivative or financial position can be vexatious on the market. It skews the market results. We should note that ETP, which is well represented, has vehemently denied all clams of wrongdoing.

A second case involving using market power to lower prices is DC Energy versus Hydro Quebec. Now, speaking hypothetically, consider a dominant supplier with market power in generation that traditionally bids energy so it won't create a lot of congestion. Such a supplier would be able to acquire FTRs from its point of injection at a cheap price because their long term bidding practices leading others not to expect substantial congestion. In the absence of congestion FTRs don't have much value. That company acquires the full interface value of capacity in FTRs at the same time that competing suppliers are trying to enter the market. This causes the price to plummet but they still earn a full return based on the higher clearing price at B because they've got all of the FTRs. I'd argue this is a case of market power lowering price to discourage competition. It is the linkage between a dominant physical position and the use of an enormous hedge position in the financial product which makes that conduct profitable. Again, Hydro Quebec has denied wrongdoing of any kind.

There is no doubt that financial transactions provide a number of benefits to the market. Speculation has unjustifiably earned a dirty name. Speculation provides benefits to the market through increased liquidity, increased price discovery and more competitive results. Purely financial traders cannot exercise market power in the real time energy market. It takes physical resources to do this. They have no ability to sustain market power in the financial markets because if they did so they would be creating an arbitrage opportunity for other financial traders.

Let's consider financial traders in the FTR markets. Adding financial traders to FTR markets increases competition and raises auction revenues. Those revenues ultimately go back to consumers, because of federal and state regulation. This can be through a direct transmission service charge credit that's a matter of ISO tariff, as is the case in New York, or via auction revenues to LSEs based on their load so they can serve load at lower price, and it can also come through state rate making where auction revenues are credited directly to retail rates. Another benefit is that as FTRs evolve into longer term products the increased competition and liquidity sends better long term price signals on the value of congestion at different locations on the system.

FTRs arbitrage the difference in the price in the day ahead market between two locations. Alternately, virtual transactions arbitrage the difference between the day ahead and real time price at a single location. Virtual transactions add liquidity as well. They're not profitable unless they bring convergence between the day ahead and real time prices, They tend to reduce the day ahead energy premium that otherwise exists.

There was a graphic example of this in FERC litigation involving the Midwest ISO. As FERC issued orders that created doubt concerning the amount of uplift that would be assigned to virtual suppliers the virtual supplies decreased substantially and the day ahead premium rose significantly, on the order of $1 billion per year. Now if somebody talked about going into an ISO market and raising schedule one costs by $200 million a year there would be an uproar. However, these were exogenous risk factors for virtuals that caused the market premium in the day ahead market to go up significantly.

Neither FTR or virtual deals arbitrage the difference in price caused by market power. With that type of risk the product is no longer pure and the speculator has an extraordinary risk factor that makes arbitrage difficult achieve. In a way financial traders can be like the canary in a coal mine. They're very sensitive to anomalous prices. The financial traders add liquidity across thousands of nodes on the system. They're looking at a granular level at what happens to prices in a way that other market participants may not. They are sophisticated and when inexplicable results occur they're an early warning system for concerns.

When financial markets are thriving, and there's liquidity and competition in the financial products, it's a sign that the market is financially healthy, competitive, and transparent. When financial markets suffer the related markets should be on notice that there may be a significant problem. This could be structural, market power, inadequate market rules, or inadequate transparency.

Here are some thoughts for market monitors. Transparency and sufficiency of timely information, particularly where there's no concern of parallel conduct or price signaling issues, is important. Consistent application of market rules is important. The impacts of market power on financial products and vice versa must be considered. While financial positions may serve to ameliorate incentives to exercise market power, there are some potential exceptions that should be examined. Financial products cannot become the private tools of those with market power to enhance their profitability. In some situations, they can decrease or increase incentives to exercise market power.

Question: In your discussion of the CFD, what happens in the physical market? Because eventually somebody has to physically deliver load 10,000 megawatts.

Speaker 3: This example was a financial transaction between a 15,000 megawatt supplier to financially hedge 10,000 megawatts of load for a city. But because it's a financial transaction there is 15,000 megawatts of energy supply from the supplier being bid into the market in some fashion. Or not, to the extent there's some subtle withholding going on or something else that's nefarious it might be less than that. The physical load is still bid into the energy market.

Alternately, in a physical delivery that 10,000 megawatts is taken out of the market. In certain circumstances this could be relevant to assessing the ability to exercise market power. I question whether in the context of a purely financial transaction there would be greater flexibility to settle the exercised market power as opposed to a situation where they've physically scheduled the delivery. This is just one of several cases where it's appropriate to question the circumstances under which it would be appropriate to decrease market share for market screens based on financial transactions.

Speaker 4.

I will contrast the previous speaker to some extent. While financial traders may be canaries in a coal mine, traders can also develop an adverse position and lose money for many reasons, it's not necessarily the use of market power or an improper market outcome. People get bad financial trades because they make mistakes.

When the industry looks at climate change, the need for new entry, increased input costs in terms of fuel, increased construction costs, the need for dramatic investments in infrastructure, it's a perfect storm of price increases. The industry has to pay fixed costs for investment on new and existing infrastructure. With everyone paying attention to financial concerns in this atmosphere, there will be claims of market manipulation. The petroleum markets are rife with concerns for speculation.

Many of the issues in California concerning high bidding and market manipulation have never been clearly shown – everything got settled. Nonetheless, big physical players in this industry are moving massive amounts of their business to the financial markets. Much of their behavior is now in markets that FERC doesn't directly regulate. All of these realities make for a highly complex situation. There are several open cases right now. Energy Trading Partners [ETP], Ameren, DC Energy versus HQ [Hydro Quebec], and the recent Edison Mission order. There is very little guidance from FERC.

FERC's market manipulation provision is supposed to be based on the SEC's authority. There is precedent there for securities markets. However the electricity trading situations can be less straightforward than SEC cases. Most of them involve disclosure. There are other FERC and CFTC cases involving false information or misreporting prices that are comparatively simple.

However, the cases I just discussed like Ameren and others involve open market manipulation. They are more amorphous. Three of the cases are supposed downward manipulation cases. That's not really what one would necessarily expect.

We should learn something from predatory pricing cases. In that context the theory is you lower prices below some appropriate measure of cost to make your money back later in the so-called harvest period in the future. However in these cases, the harvest period is a parallel market right alongside. The Supreme Court's cautioned about the need to distinguish between legitimate vigorous competitive behavior, which does drive down prices, and inappropriate predatory conduct. It's important not to chill competitive conduct that benefits consumers by lowering prices without being sure there's nefarious conduct.

For these cases, intent needs to be shown and so does manipulation, or deception. The CFTC, SEC, and the FERC's show/cause orders all require these to make a case for market manipulation. Did the supposed manipulator force prices to be something other than the natural outcome of supply and demand? An artificial price. The government seeks to see a big financial position, which shows motive. They also need to show intent to some degree. We don't have guidance for how to look at what the fundamentals tell you the prices should have been? What about the actual bids and offers in the trading data, what is shown there? They need to look for strange behavior.

If one doesn't see behavior like that then what else does the government look at? We need to see where the government goes to find a measure of artificial price. It shouldn't be the case that they tell anyone with a physical market presence that if they have an advantageous financial position they're guilty if they engage in physical conduct that can affect the financial position. Especially if the physical conduct was legitimate.

What we need in these cases is a discerning thorough look at the underlying market conduct and fundamentals to see what it tells us. That is not yet in place at FERC. The CFTC enforcement people use their chief economist 60% of the time in their cases. FERC enforcement doesn't have a function like that built yet. These cases require complex statistical analyses. If it's not being done then they run a risk of confusing legitimate market behavior with manipulation and detecting false positives.

In the ETP case, the FERC staff and commission in the show/cause order proposed a method of detecting artificial price called the implied price theory. They would look to the derivatives markets to see what the right price should be and imply the right price for the physical gas markets. They claimed this was the right price to within 2-3 cents on a $9 trade. If an entity was three cents below this price then the entity must have manipulated the market. In that kind of case, something like 40 to 70% of all natural gas price outcomes around the country are manipulated. There were soon headlines saying implied price theory was junk science. They need a more sophisticated economic analysis.

Looking at specific trading behavior they need to understand the entire position, both financial and the physical side, but that's not all. The underlying conduct must also be analyzed in a sophisticated way. The economists have tools to do this, and have been doing it for decades on the securities side. It's time this is used within the electricity industry.

Question: There was a discussion of the asymmetry of failing to mitigate when needed versus mitigating when it isn't. The claim was that mitigation is usually relatively inexpensive. However I'm not sure of that. For example, Texas is institutionalizing hockey stick bidding to incent folks to bid a lot above marginal cost, particularly when the market gets tight. This is to get the prices up so that they can provide enough revenue through the energy only market without a capacity market.
We all know scarcity pricing is important. An implicit assumption in the argument about the asymmetry of mitigation is that there is adequate scarcity pricing. If there isn't adequate scarcity pricing, and the ability of hockey stick bidding to establish prices that get the energy price high is constrained. More money flows through capacity markets and creates all the other problems. Does the argument about mitigation depend upon the assumption that there is adequate scarcity pricing? Should scarcity pricing be a high priority item to justify an bias towards more rather than less mitigation?

Speaker 1: I don't think it's true regardless of what the mitigation scheme is. One could design a nasty mitigation scheme that actually damaged markets. The PJM approach is a rational market power mitigation scheme. Some would argue it's overly conservative.

Wholesale power markets are designed to always be long in order to get reliability. So there has to be some management of revenues. Texas has figured that out and basically they're mandating market power depending on when they do hockey stick bidding.

A market operator can let market power be the design element for achieving revenues, or scarcity rents, or a capacity market, or some blend. It's unstable both politically and financially to have market power be the key mechanism to provide revenue adequacy, incentives, and the right price signals. Scarcity pricing is an essential piece of that package. It is fine to link removal of the exemptions for market power mitigation to the implementation of scarcity pricing. That is needed.

The pressure is less in PJM because they're getting adequate revenues through the RPM markets. Now they ought to shift a substantial amount of those revenues back to the energy market. The only way to do that is via scarcity pricing.

Question: What is meant by hockey stick pricing?

Speaker: Let's say one has a unit whose marginal cost is $200. A hockey stick curve would allow you to raise the price on the tail block of that to $1,000. The shape of the demand curve gets vertical at the end. In a market where price is set by the last unit dispatched those units can drive the price high. The result is in aggregate a hockey stick shaped curve. The only question is whether the high prices are coming from scarcity or from market power.

Speaker: In one of the California cases FERC said hockey stick bids were unacceptable. However, in the eastern markets they are accepted when there's an operational basis. For instance some units are a lot more expensive with their last increment of emergency output so that curve reflects the reality of those units. A market monitor has to pay attention to those issues as well.

Speaker: Yes, if you add duct firing for example to a combined cycle that raises the price. If you add superheating of the steam to that it also raises the price. To me that's not a hockey stick curve, it's simply reflecting the marginal cost. The marginal costs are simply higher in the tail block. To me a hockey stick curve raises the tail block above the actual incremental cost for purposes of setting the price.

Question: We heard about the uncoupling of structural market share tests for markets that involve physical and financial assets, and the practical difficulties of linking those to a structural test. What value are those kind of tests in the context of a market that has effective market monitoring mitigation? What is the value of that in an RTO that already has market monitoring mitigation?

Speaker: Modifications to the current static test should be made to recognize financial transactions. Static answers do not address many of the issues that have been discussed in this panel. However, one needs to pass the FERC test in order to have the right to bid at competitive prices in an ISO market. The answer is on one hand that if a company is going to pass the FERC test by tweaking it, they need to consider the conditions and the factual showings to satisfy that. On the other hand there's still a more dynamic test in play with the market monitoring unit. Unless you're saying that FERC shouldn't worry about these tests any more because market monitoring will take care of it.

Question: That's what FERC is saying. They've said the default mitigation in the market power rules under 697 is trumped by the existing market mitigation rules of each RTO.

Speaker: The need to still make FERC filings to go through the analysis will meld the static tests with any supposition about dynamics in terms of financial transactions. However, the ability to stay on top of the data associated with dynamic financial transactions is a great challenge and a serious implementation issue.

Speaker 1: The FERC market based rate test makes no sense in the context of a dynamic market like PJM and the other RTOs. FERC should still have authority to define what market power is. They could do more there. They should rely on the market monitoring being done by PJM.

Second, it is impossible to understand every company's net position at any point in time. If so, can an RTO still appropriately limit market power in a market like PJM with clear rules about behavior and market power mitigation? Absolutely. There are complexities, and there are incentive effects, but it doesn't mean that complete understanding is needed.

Speaker 4: Yes, in the end they need to look at the physical market holdings of a company to assess the issue. Putting aside unusual circumstances, they can put aside financial issues and focus on problems in the physical markets. If there's no problem there, then the financials don't need to worried about. Physical market conduct that's objectionable has to come first before examining financial positions.

Speaker: If FERC is going to have screens to look at what the incentive is, they can't just pretend that all that matters is traditional or conventional load following sales. They have to look at these other transactions. They'd have to make some assumptions but that's not new to FERC.

Question: Sometimes market manipulation and market based rate issues get mixed up. In between is the better position because the PJM tests lack a sustainability concept, right? Theirs is for just a few minutes and doesn't look at whether the supplier is serving load and is hedged. On the other hand the market based rate test is static and doesn't look at changing loads. In a world where load auctions are going to shorter periods of time how does that work into the market test? In New Jersey BGS contracts for three years, how does PJM handle those market based rates? What happens when they start going to three months in Maryland, how will PJM do that?

I'm not clear about how financial transactions are being taken into consideration. For a generator engaged, their generation is their ultimate hedge. The only thing to look at is how they're bidding in their generation. The only exception is what we saw a year ago in MISO using the ramp inappropriately to match a financial. Until a market monitor gets an actual physical manifestation of wrongdoing to match a financial, I don't know why the financial transactions should be included.

Speaker: Sustainability in a commodity market like the wholesale power market or pork belly futures. I'm not sure what sustainability means, it's not part of an economist's definition of market power. If incentives are in line and an entity is behaving competitively then there's no problem. Alternately, requiring them to behave competitively doesn't cause harm. The notion that sustainability means that the market monitor should show that an entity has affected the market only to the tune of $100 million but $300 million is the threshold before they act makes no sense. Doing the test as we roll on in real time makes sense in these markets.

Question: I'm interested in the case of New York and Hydro Quebec. In the initial period the monopolist had bid in such a way that they had uncongested the interface and were selling less quantity in order to get a higher price. In the second period they purchased FTRs, and bid their supply lower to increase congestion and sell a higher quantity. This caused harm to other financial players who had relied on the historical low congestion pattern that was there. Which is the market power? Is it bidding a low price and high quantities when you own the FTRs, or is it bidding the high price and lower quantities before you own the FTRs?

Speaker: That's a leading question. It's an interface with a single dominant supplier that will act as a monopolist would normally act. They will sell output into the market to receive the highest price or refrain from selling output if there's greater value at a different time. This can be done with hydro. They are not selling an appreciable lower quantity since they controlled the interface effectively and it's a 1,500 megawatt interface. They were bidding in to ensure they would receive the clearing price at Marcy, the reference node in New York, rather than at the HQ node or the proxy bus between New York and Quebec. They weren't giving up a substantial volume of sales at all.

FTRs, or TCCs as they are in New York, are very cheap on an interface that is not congested. So if a party accumulates 1,500 megawatts in TCCs which equals the interface limit at the same time it is aware that 600 megawatts of competition will enter the market at the HQ node, then as soon as the competition hits the market it causes the price to plummet. However, it does not benefit any load because the load is still paying the congestion rent to go from the HQ node to the Marcy node. What is the effect on the competitors that just entered the market?

HQ sold 600 megawatts of energy, HQ distribution had a supply contract with HQ power and the supply contract had an option for a phased increase of 600 megawatts. HQ distribution magnanimously offered to turn that capacity back to HQ power because it didn't need it. The Canadian regulator decided that HQ distribution should auction the capacity off so ratepayers could receive the benefit of that value.

So there was 600 megawatts of new supply that would be bidding into New York. In parallel with that process, all of the 1,500 megawatt interface limit in TCCs was acquired by HQ productions affiliate. As soon as the competition entered the node at New York the price plummeted. What did that do? It gave HQ not only the return on the energy it was selling into New York, that is the difference between the price at the HQ node and the price at the Marcy node, but it also gave HQ the congestion price differential on the competitive supplies by third parties and energy. The impact was not merely on a counterflow TCC holder, the impact was on physical supply that entered the market in competition with HQ power. If the price plummets what would one expect the physical supply that came in to do?

Question: I think suing might be a good approach. A supplier in that region should be very cautious about getting involved in a market that is not competitive as a market participant whether it's in FTRs or on the generation side.

Speaker: HQ has the largest generation system in north America, something like 45,000 megawatts of hydro. One of the reservoirs is the size of Rhode Island. They are accused of selling too much clean hydro power into New York State at too low a price in order to make up the difference via FTRs/TCCs in New York. Their lawyers believe HQ has acted with a legitimate business purpose and in a fully competitive manner. The tests discussed earlier hold for this case as well.

There is a question of whether there was any material or physical leverage because the TCC holdings are not multiples of physical flow. They should look at physical market activity, determine whether it's legitimate, and if it is what a competitor does on the financial side should not matter. It could have ten to one leverage. They have just been a smart competitor. There may be disagreement with some of the facts that have been discussed but it doesn't matter because the analytical framework should focus on physical market activity.

Speaker: The whole matter is still pending at FERC. However, in this situation load is not benefiting from lower prices either. The congestion just got moved around from and between the HQ node and the New York Marcy node. The load is paying the full 1,500 megawatts of congestion rents on the TCCs.

In a purely financial situation if somebody makes a bad bet then somebody else can arbitrage that position. However, when physical market power is dominant then other players don't know when congestion will be turned on or off. It's not as though somebody else other than HQ could come in and bid up the price of FTRs. The combination of market position and FTRs becomes a cornering tool to manipulate prices. In this situation there is no benefit of lower prices. One of the differences between this and a predatory pricing case is that in predatory pricing consumers benefit from lower prices for a short period of time. We'll have to see what FERC decides.

Question: How does PJM distinguish between legitimate scarcity pricing and the unlawful exercise of market power?

Speaker 1: First, scarcity pricing is an administrative determination. In New York there's a demand curve with set prices on it. It's somewhat arbitrary but they get the job done, they make prices higher. PJM has a flawed scarcity pricing rule but nevertheless it's that rule that indicates when scarcity pricing is appropriate. When market tests fail then PJM takes emergency actions that the price in the affected area can go to the highest price offered by any operating unit. It needs to be made a lot more sophisticated. The rules now are clear, but not sophisticated or carefully thought out.

Question: In the early 20th century there was market power exercised in the railroad industry and sunshine regulation was implemented. Essentially the more exposed the market power issue is, the more it's available for the public to look at, and the more embarrassed actors would be to be seen doing it. Could this apply to our industry? Would more complete disclosure of transactions and/or positions help in that process?

Second, most physical participants would not want their positions nor their operational aspects to be made public. Why is that? Either they think that information is important for them to maintain an edge in the market, or that could be used against them by someone else for market power reasons, or it is useful to use for market power reasons. What are most people worried about?

Speaker: The FTC made comments recently to FERC to be careful about too much transparency because it creates problems of parallelism and other issues. From a supplier perspective, most people can figure out what kind of machine somebody has and much of the cost information is semi public. Many probably model all this already, right? What remains that is not generally publicly available would be viewed as competitively sensitive. As long as the market monitor has it, the right protections are in place.

Speaker: Companies are already very concerned about doing something wrong and the implications of that for their business, without any additional transparency. It is risky behavior that shareholders don't like. Most companies have a lot of skill and acumen they use in a legitimate and competitive way. The hedging and financial tools are generally very legitimate and used in sophisticated ways to make companies more efficient and to maintain compensation levels. Finally, the market monitors take care of it. They don't have access to everything but they're watching the markets on a daily basis.

Speaker: The ISO markets are diverse and complex. The more transparency there is without compromising secure company data, or resulting in parallel behavior or price signaling, the more cops on the beat there are. These are the other market participants with economic interests in ensuring the market is being run fairly. Transparency shows not only market power but market rules, software flaws and improvements. Those participants can't change the rules but they can go to the RTO or market monitor to seek improvements which ultimately benefit consumers like through the adoption of more efficient market rules and the correction of market design flaws.

Speaker: ISO price formation processes should be more transparent and market rules too.

Speaker 1: There are two broad models of this. One is to make everything transparent, every last detail of physical and financial players' positions in every market. That together with strong market power mitigation rules could work. It would be a very dramatic change from the current system.

The current model is to increase transparency while avoiding encouraging collusion. The PJM markets can get better about being transparent. For example data on averages for generation and transmission outages could be made available. It's not clear why certain players should have advantageous or differential access to some of that information. Opening all the books is probably too difficult so they should be smart about being transparent; more systematic and active.

Question: As these markets become more financial in nature and overlap with parallel markets, is FERC developing a structure may already exist in the financial market oversight, via the CFTC, FTC, or SEC? Should FERC do this, or overlap with another agency, or let another agency do it?

Speaker: While I've criticized FERC, I also praise them. Their enforcement regime is much better. They've had several recent strong rulings, and their economic analysis is getting more sophisticated. They do need collaboration with other agencies. They may lose the Ameren case because it's entirely financial market activity but we'll see. The physical markets need to be protected and they should be free of harmful manipulative activity to the extent they can reasonably be made so.

They need to develop some expertise but they're already working alongside the CFTC. There's a memorandum of understanding. It may ultimately become a bit like the DOJ and FTC, a merger. But which agency gets it? They negotiate behind closed doors. Usually DOJ gets electric and usually FTC gets gas. There are mechanisms already in place to do that. People talk about merging the SEC and the CFTC. That would make more sense than merging FERC into one of those two agencies. The cooperation is already built in so I don't think any changes in that regard are really needed.

Speaker: FERC views FTR markets as the financial equivalent of firm transmission service at a fixed price. The virtual markets and the FTR markets are an integral part of the ISO RTO tariff structure. It's much different than the Ameren case where the financial transactions were occurring in a market outside of FERC's jurisdiction.

Speaker: Right. The CFTC folks believe manipulation of the electric markets is at the heart of what FERC does. They view natural gas as more their bailiwick and that division makes sense. Carbon is also a commodity to the CFTC, so manipulation of carbon trading may be pursued by them.

Question: Why isn't there an independent market monitor outside of the RTOs given some of the same market power concerns across the various RTOs? It would be more on the physical side than financial, and look different than the PJM market monitor?

Speaker: Makes sense to me. [LAUGHTER]

Speaker: Yes, a good idea.

Speaker: That's FERC's job. They have an enforcement staff and market power screens that are now quite rigorous. In general FERC early on said that bilateral trading activity wasn't something it expected to pursue from a market manipulation perspective. Market manipulation is fraud under FERC's statute. They said lawsuits are also available. I expect that will change. I don't think we need another layer as long as they are doing their job.

Speaker: One of the issues at the most fundamental level is price formation. Regulated markets are not transparent. It's an issue for everyone in markets who abuts a regulated jurisdiction is the lack of price transparency. The question is whether FERC's monitoring is structured properly to make those markets more transparent.

Speaker: From a legal standpoint it would stretch FERC's conditioning authority over market based rates in a 205 context or if there were a merger in the 203 context. FERC has not been pursuing that lately.

Speaker: US electricity markets are unique. Is there any other market in the world that has that degree of mechanical sophistication and transparency to it? I haven't seen analysis that shows there's a huge competitive problem that needs to be solved in non organized markets through additional monitoring. Most of the trade is bilateral and often on a term basis.

Question: Let me follow up on the transparency issue. You all agreed there's no reason to give out that information immediately because you're concerned that competitors would use it to advantage themselves. Six months later the bid information is available for everybody to take a look at in New York and PJM. Is this time differential the right one?

Speaker: In New England it's three months now. FERC's notice of proposed rule making suggested a 3 month default with variation. Some arguments say they should wait until the trading season is over before the data is released. Once the data is sufficiently stale it's not going to produce parallel conduct. Things change sufficiently over the course of a year and old data is irrelevant.

Speaker: I don't know whether 3 or 6 months is right.

Question: So who does the release have value to if it's so stale that no one can tell anything from it?

Speaker: The theory is that one can look at it and see if there's problematic pricing. It is possible to analyze the data in various ways. It's just not clear whether it is useful to the market or not. There are quarterly reports as well under the market based rate program.
Speaker: If a company is doing sophisticated modeling it's possible to use that data to infer heat rates and characteristics about units which they can apply to current and forward fuel costs. It has market value. It's used differently by different folks.

Question: In the discussion of PJM's approach earlier, it seems that acquiring financial information is so problematic that the cost benefit tradeoff isn't worth the trouble. They should mitigate based on gross rather than net positions. I presume they don't extend that to ex post evaluation of manipulation charges. In other words, that the financial information would be relevant there? Is that correct?

Speaker: I agree with your characterization of ongoing reviews. If they were to look back to determine whether a market participant exercised market power they would look at every relevant aspect, including trying to assess their incentives. At that point they would look at their position for the defined time period. It would be very difficult to provide that information on an ongoing basis to PJM. But certainly for evaluating a particular instance, they would look at all relevant information including financial.

Question: That's different from what you said earlier. You stated that there's no judgment exercised in connection with making that determination.

Speaker: My earlier answer was about ongoing automated local market power mitigation and scarcity pricing. My answer to the current question, if there's a particular case to look at, they do an investigation. There are cases where there's a potential to manipulate the market that fall outside the rules. They have to look at them because they fall outside the rules. In that case they do an investigation, it becomes more ad hoc. They do look at incentive related information including net position.

Question: My question is what standard do they use in connection with those investigations to distinguish between legitimate scarcity pricing and the exercise of market power?

Speaker: I'm sorry, I misunderstood the question. For investigations outside the direct application of the automated rules, they would look at a variety of facts including incentives and also whether the market was scarce. To evaluate scarcity they use the publicly stated tests: local level of reserves and local market conditions. Unlike Texas, it's not the job of individual generating entities to determine when there's scarcity. That's the reason they need systematic rules; so it's transparent and no one has to worry about running afoul of it.

Question: Is there a more specific test? If sellers in the PJM market want to know when they might be subject to an investigation if they bid above marginal cost, what is the test? Or if they bid above marginal costs is it automatically exercising market power?

Speaker: The first screen would be the relationship to marginal cost. If there were a rule it would be written down. There is no rule and they don't have the discretion to make a decision about market power. They have the discretion to refer it to FERC. Offers above marginal cost that affect the market price are looked at. They will discuss it with FERC and make a formal or informal referral to them.

Question: Should run time limits should be taken account of when computing marginal cost?

Speaker: I'm not sure I know what that means. Certainly they look at operating parameters of units. Operating parameters of units need to be physically based or they can be a method for exercising market power.

Question: Run time limits mean that one's permit allows one to run X hours a year. Can one bid in opportunity costs to reflect the cost of that constraint or no? Is that under marginal cost?

Speaker: It's a great question. If there's an explicit government hard cap on run hours, not one that's viable through and not one that's related to fuel excess. It should be included in opportunity costs. They have done that with a market participant and are discussing a systematic way of assessing that.

Question: It wasn't clear whether you meant opportunity cost or marginal cost in a physical sense. If a supplier bids above that level there is at least a presumption that they're engaged in market power. The supplier would have to demonstrate that there was a legitimate scarcity or other reason to bid at that higher level? Is that the standard?

Speaker: That is PJM's view but remember that they're not the enforcer of it.

Question: Is it OK for suppliers in PJM to bid scarcity in as opposed to bidding the opportunity costs and the short run marginal costs?

Speaker: No. Except following the scarcity rules and in that case scarcity pricing rules are very clear. They define when scarcity price will be set and it's not being set by the ongoing offers of individual units.

Question: You stated that if there is no dysfunction in the physical market then a monitor doesn't have to look at the financial market. Is that correct?

Speaker 4: The word dysfunction is encumbered by California and the ninth circuit's decisions. I didn't meant that a monitor should not look. What I meant was that they should not stop just at the financial markets. When they're looking ex post at a manipulation allegation, they should understand all the incentives. All the potentially complicating factors should be examined. Further, just because there's an incentive doesn't mean that one is guilty.

Question: My concern is with the separation of the physical and financial market. The financial market is becoming much larger and trading faster than the physical market. Do conventional definitions of market power capture dysfunctional behavior in the financial market prior to the fact that it could affect price and behavior in the physical market?

I strongly disagree with the presumption that if there's no dysfunction in the physical market then they don't have to consider the financial market. Dysfunction in the financial market can create dysfunction in the physical.

Speaker: I was addressing a circumstance where a company has physical and financial positions. They manipulated the physical market and have an incentive through their financial position. Of course there can be manipulation or improper trading activity that the government should try and remedy that is solely financial. That's the Ameren case and if CFTC can demonstrate it then that's a perfectly legitimate line of investigation. Same with FERC if it proves to be their jurisdiction.

Question: What about the transparency of operator action? In many instances there is operator action using judgment or reliability to override the dispatch or pricing signal. It can suppress price but there is no transparent reasons for the actions.

Speaker 1: More transparency should be the desire outcome. PJM has this prefect dispatch project ongoing. They're trying to do it but it needs to be improved.

Speaker: Overall, the markets will function better if there's transparency and consistent application of market rules. FERC recently required the California ISO to improve the procedures for modifying the market rules. This included defining better the circumstances when the ISO could override a market rule. That's a good model.

Question: A clarification on data release at six months. It was set originally because that was the break between different reliability periods. It was also done to get data out to academics and researchers as FERC was trying to improve the markets and market monitoring at the time – this was around ten years ago.

Moderator: Has the six month data actually done that? Has somebody gone back in the data and said to FERC or an RTO that something is wrong?

Speaker: Yes. People bring incredibly detailed results. Some analysis is good and others less so.

Question: The bid data when combined with EPA data which has heat input, gross output, can also be used to piece together which units are out there and identify those units by people who know the industry well.

Early there was a discussion of institutionalizing hockey stick bids in Texas instead of a capacity market. There are capacity markets in the other RTOs, so what really is market power? How do we define market power where there is no capacity market versus defining it in a market like PJM? Some might say that any price over marginal cost is market power. However in an energy only market like Texas, price can be over marginal cost yet generators can't cover their going forward cost. Is that really market power? Is that a long run sustainable situation for generators?

Speaker: It depends on what the rest of the components of the market are like. If the market design tamps down the energy market severely and there's no other mechanism to allow appropriate cost recovery then the definition should be relaxed. Especially if the overall price outcomes are consistent with what you would expect.

Speaker: None of the large wholesale power markets would pass a test for a sustainable market. There have to be incentives to enter and invest. There are two basic models. You can simply permit unmitigated market power, or you can a design scarcity pricing approach. If every generator in Texas can put in a hockey stick curve and that means that even though there's adequate supply behind a constraint and there's only one owner that the price can be set to exercise market power then that's not an appropriate outcome.

The market test should show competitive pricing when the market is long and when the market's tight. If the market's tight then the definition of competitive price is no longer short run marginal cost, as I've tried to make clear. This is also consistent with a sustainable market.

Question: What is the best approach for a generator anticipating future carbon costs of compliance with RGGI or some other carbon plan? A supplier can reasonably anticipate bids for 2013 in a capacity market that will almost certainly have to address carbon costs. How can they submit these costs and yet not appear to be involved in market power?

Speaker 1: First, in the energy market it's irrelevant as your question assumes. The question is if there are fixed or investment costs associated with meeting environmental compliance goals going forward can they include them in an offer in PJM's RPM capacity market? The answer is yes.

Question: Before they know exactly what they are?

Speaker 1: Right. They can't simply include any costs. There's a clear test in PJM's tariff for it. The company has to commit in writing, and if they affect the market clearing price and don't ultimately spend the dollars they have to pay that money back. The goal is not to exclude incremental costs associated with meeting government mandates. Future environmental compliance creates uncertainty, so the markets have to reflect everyone's best reasonable estimate of what those costs are.

Question: Do market monitors look for the possibility of manipulation in the environmental allowance markets, SO2 and NO2 so far, CO2 to come?

Speaker 1: PJM runs a market called GATS, generator attribute tracking system. It's outside of FERC regulation. It's a market in generator attributes even though they don't call it a market. If states and state entities buy and sell it is subject to manipulation. So far it is not extensively looked at but I believe it is a potentially serious arena for market manipulation.

Question: Is there any research that shows this occurring?

Speaker: Not that I've seen.

Speaker: The CFTC thinks carbon's a commodity, so they would see manipulation of those markets as jurisdictional. In the California refund case, Dynegy was accused of manipulating the allowance market to raise the price of electricity. The FERC rejected those arguments, correctly. Some of the arguments between jurisdiction, physical, and financial instruments can get absurd. What about railroads, steel? If Japan is dumping steel does that mean that electric prices are manipulated downwards? If there is a conscious scheme that could be proven then it would be prosecuted but these sorts of things are very hard to prove.

Session Three.
Debt by Any Other Name:
Are Ratings Reality? Does the Accounting Make It So?

A number of utilities that have in recent years entered into PPA's for new capacity have looked very seriously at re-entering the generation business by building rather than buying. Among the incentives for *doing so is the perspective of rating agencies and accountants who look upon long term power supply agreements as either debt on the balance sheet or long term capital leases, which, in either case, require the purchasing utilities to increase their equity in order to retain an appropriate capital structure.*

As a result, a number of utilities are asking themselves why, if they have to increase their equity ratio, should they not build for their own rate base and earn a return rather than increase equity to cover for highly leveraged counterparties? Others, however, contend that the accounting or rating agency treatments of PPA's is erroneous, in that it is not the utility which is exposed to PPA risk, but rather that the exposure is covered by the revenue stream coming from customers. Still others suggest that if there is risk exposure, it should be resolved not on the utility balance sheet but, more appropriately, on the balance sheet of the selling IPP, and that putting it on the utility is a form of subsidy. How should rating agencies and accountants look at PPA's? Does it make a difference when state regulators pre-approve PPA's? Beyond that, and perhaps of greater policy import, if utilities do have the reflect PPA risk on their books and respond by building rather than buying in the future, what does that mean for competitiveness in the market over time?

Speaker 1.

Debt imputation by the rating agencies is not a new topic. It's gaining more attention because contracts are changing. Over the years there have been changes, updates, and revisions to the criteria but it has been in place for almost two decades now.

Let's start with a quick review of what a credit rating is. Companies like S&P, Moody's, and Fitch provide capital markets an opinion of credit worthiness; the likeliness that an issuer will default on its financial obligations. The letters they provide are called the "shortest editorial in the world." It is not science. It is more of an art. A rating is the result of a host of different factors and influences that go into the analysis. In the utilities practice the analysis has two components: the business positions and the financial profile. The business position is primarily the qualitative aspects of a company's business. In utilities they're looking most importantly at regulation. They're also looking at the markets the company serves, operations of the business, competitiveness, and management. Second, they consider the financial profile. The analysis is the intersection of those two different aspects.

Why make adjustments to audited financial statements? Most ratings use statements as a great place to start but they don't capture the analytical truth; the overall credit worthiness and nature of obligations a company has. The adjustments provide a more accurate depiction of a company's obligations, rights, and liabilities. This provides investors a more accurate picture of relative risk from one company to another, and over time. There are a host of financial adjustments made to the balance sheet and income statement cash flows. The more prominent are operating capital leases. This is done with all industrials. PPAs, purchase power agreements, are also included. They also consider the obligations companies have entered into with pensions, other post retirement benefits, and asset retirements.

The rating agencies also subtract things, specifically securitized debt. It's not all adding on. For instance, many companies issued stranded asset debt many years ago. However, that was legally and structurally an obligation for the ratepayer, not the company. Those companies effectively acted as a clearinghouse for the obligation. They account for hybrid preferreds too. The agencies split the instrument between a debt and equity component.

The fundamental ratios affected are those that are cash flow driven, that really depict the cash flow generating capacity of a company relative to its financial obligations. All the adjustments made to the balance sheet or income statement have an effect on these fundamental ratios. The ratios dominate the agency analyses. Finally, the rating outcome is always the decision of a committee. No one person makes these decisions.

In the utility sector there are about 400 different kinds of off-balance obligations that are considered. There's about $485 billion of total adjusted debt in this sector and about $30 billion is off-balance sheet debt considered by rating agencies. The most significant types are operating leases, followed by PPAs throughout the industry. Less than 10% of the total debt is imputed debt. Similarly, they impute around $4.8 billion of interest on 35 billion of total interest on an annual basis, a little over 10%.

PPA debt imputation has a 20 year history. The initial reason was to compare companies that built versus companies that buy. They had different financial structures and the idea was to make them easily comparable. Debt imputation would incorporate the risk that companies took on when they entered a PPA.

There are risk benefits in PPAs too. They shift construction and operating risk, and reduce cost variability. The contracts provide cost security over time, and provide fuel supply diversity. However they are not risk free. They are a fixed obligation of the company and must be incorporated into the financial profile. Their recovery depends on the willingness of regulators to view them as prudent, and to pass their costs through.

The component of the PPA that is debt-like is the capacity component. Not all contracts have capacity components but it's usually the capacity and energy component. The energy is the fuel, the capacity is where the company that is providing the power recovers its fixed obligations, including its debt service.

For the capacity payment they take the net present value of that stream of payments at a discount rate equivalent to the company's cost of debt. Let's consider a company with a PPA of $500 million each year for 13 years. We'll consider the practices of one of the largest rating agencies. The agency will present value that stream of payments at 6.5% which results in a $4 billion amount. However it is not pure and simple debt so they risk adjust that amount. The risk adjustments are based on the certainty and timeliness of the recovery mechanisms that the regulators have set in place. This is set primarily to the extent that the capacity payments are recovered in base rates. It usually ends in a 50% risk factor. If the capacity payment is captured in a fuel adjustment clause they will apply a 25% risk factor. Other agencies may do slightly different things. The difference occurs because the timeliness and certainty of recovery differ slightly. When costs are recovered through base rates, they go through a litigated process. It's messier and not as timely. In this example the company has a fuel adjustment clause to recover its capacity payments so the agency takes the $4 billion and applies the 25% risk factor so it totals about $1 billion.

There's also an interest component associated with this. The agency will use the same discount factor, 6.5%. So 6.5% on $1 billion of debt is about $66 million. The $66 million of interest lands on the income statement and the cash flow statement. The agencies do revise their criteria from time to time, and now they include a depreciation factor. This tempers the effect of the PPAs and they become much less punitive as a result. In this example the unadjusted metrics had FFO interest coverage of 4.8 times. After the depreciation adjustment FFO interest was 4.6. FFO total debt falls from 25% to 23%, and capitalization increases from 53 to 55%. Not overwhelming, and not enough to change a rating without other factors occurring, but in some situations the depreciation may have a rating impact. I'll end it here.

Question: Do the agencies consider the PPAs marked to market. If the PPA is in the money significantly how is there any risk at all? If it's out of the money, maybe there is risk there. Is this considered?

Speaker 1: That's a legitimate point. I know agencies have considered it but have not gone that route. The rating is simply an analytical tool for a financial obligation. That's all it does. Maybe in combination with a host of other things it could result in a change in the outlook. There are few single examples that will actually change ratings. There are a couple of companies with massive PPAs. For instance Central Vermont has the Hydro Quebec contract and this changes the rating. The agencies have tried to make this as simple and straightforward as possible. It may not always be 100% accurate but it's generally very close.

Speaker 2.

I will focus on accounting concerns for debt consideration. In 2003 the FASB (Financial Accounting Standards Board) issued two new accounting standards. There was additional guidance on lease accounting which brought PPAs, particularly take or pay arrangements, under the scope of lease accounting standards. They were now treated as capital lease obligations and added to the balance sheet as a liability.

A more onerous standard was FIN 46 that provided a new accounting model for consolidation of entities. The intention was to address special purpose entities [SPEs], a structure which led to the demise of Enron. They had difficulty defining what structures fell within the scope of SPEs so they extended the definition and made it so broad that virtually any entity, including PPAs, could fall within the scope of this new accounting consolidation model.

Let's consider some background on the two consolidation models. Traditionally, consolidation of an entity was always based on equity ownership or voting interests. So if a company had more than 50% ownership in an entity, it would be considered a subsidiary and consolidate that subsidiary into its own financial statements. FIN 46, the new accounting standard, introduced a concept of risks and rewards. Ownership was no longer a criteria to determine consolidation. Instead, consolidation is done by the company with the majority of the risks or rewards. The accounting standard applies to any variable interest entity, i.e. one where the equity holders do not have a controlling financial interest. For example, an entity which is thinly capitalized, where equity holders do not have decision making abilities, an entity where equity holders rights to returns are capped by some form of contractual arrangement, or one where equity holders are protected from losses. These aspects are what put PPAs into this accounting standard.

So FIN 46 has caused a lot of concern in the accounting and financial reporting industry. It has led to some unexpected conclusions. One such example is power purchase agreements where the utility can "own" the power plants that are supplying power to them. In evaluating how this new standard applies to PPAs, a utility must do a case by case analysis of every contract to determine whether that contract creates or absorbs the risks of the power producer. In a situation where a contract is creating additional risk then FIN 46 doesn't apply. But where risks are being absorbed by the utility the standard does apply.

For example, consider a contract for a majority of the output of a plant over a 15-20 year contract with variable pricing tied to fuel. This would absorb the majority of the risks for the power producer and be within the standard. The utility would have to consolidate the power producer and reflect their financial performance on its own balance sheet and financial statements. However, a *fixed* price contract in a gas fuel plant probably wouldn't lead to consolidation. In a hydro or renewable energy plant it might still.

The accounting model, unlike a rating agencies debt imputation, completely ignores any mechanism to recover costs or pass on risk to the customer. It strictly looks at the contract between power producer and utility. If risk is mitigated beyond that, it is not considered at all. From a financial reporting perspective, consolidation adds risk to the utility. The utility is responsible for making an assessment about the risks of the power producer. They are obligated to obtain all information about the various risks the power producer is exposed to and evaluate who bears the majority of the risks. FIN 46 prescribes a model to do that. It can be accomplished qualitatively or quantitatively; for instance looking at future cash flows and deviations from those cash flows.

If consolidation is required then the utility has to obtain quarterly information from the power supplier to report for SEC purposes. It's not only just financial information. A utility must also ensure there are adequate internal controls at the power supplier. Under Sarbanes-Oxley the utility management has to certify that the internal control environment is adequate. Any of these deficiencies in reporting financial information or the internal control environment could lead to an audit scope limitation. This can be a real problem for a utility. Depending on how directly relevant a contract is to their balance sheet, they could get an audit scope violation if the IPP refuses to provide them with the information. Or if there's a material control deficiency which is not remedied. It can make it difficult for a utility to get a clean audit opinion, and that has impacts on borrowing. It increases the cost of capital.

In the real world, some utilities have old contracts dating back to PURPA. Old contracts prior to 2003 are grandfathered, but if they need to be renewed they are subject to FIN 46 standards. The new standards are a real impediment to contract renewals. It's a risk to rely on the IPP to get the information for 15-20 years when consolidation is needed. Rating agencies may look through the accounting treatment and use their own debt imputation model to determine how much debt is added on the balance sheet. However this accounting standard directly adds debt on the utility's balance sheet. It's not debt equivalence, or imputed debt, it's actually there. Of course, debt imputation also has its own set of risks. A variety of things affect the cost of capital. If a utility rebalances its capital structure to include more equity that could increase the overall cost of capital and decrease the market value of the equity.

There are other considerations as well. A PPA transfers risk back to the utility, and to its customers and investors. This is no different from the traditional regulated environment. It's this risk transference that causes debt imputation and accounting issues. Retail access is a concern if customers are migrating away. Some utilities in competitive environments have lost over 50% of their load. Strandable, or stranded, costs are also a risk if contracts become uneconomic in the future. Utility customers and investors would bear these costs. In some areas, there are market mitigation measures where a utility could be required to bid in new contracts at a price that may not clear the market. In that case the capacity they bid in would not count towards their capacity requirement. They could wind up paying twice for the capacity, once through the contract and again in the market through the demand curve design.

There are other alternatives to long term power purchase agreements to encourage new supply. A market that is predictable and consistent would send the right signals to the investors and allow better use of hedging strategies. A three or five year forward capacity market could also allow investors to more easily obtain financing with some predictability of cash flows. Price or credit support, to the extent needed, could be provided by government or a similar entity. Utility build is an option which could be considered as a reliability backstop solution. If the market fails and there is a reliability need there is the option of utility build. The utility would have control over the plant, the operations and cost. Thank you.

Question: To confirm, the utility's mechanism for recovering this cost in no way impacts the financial accounting treatment of it?

Speaker 2: That's true. That part of the equation is ignored. The accounting standard just looks at the agreement between the IPP and the utility. It looks at it from the plant's perspective. Any mechanisms the utility has in place to mitigate or pass on that risk are not considered. If the utility is merely an agent and just collecting these costs from customers on behalf of regulators, or if there's an agreement with a regulator and the utility is an agent, then the accounting rules would view the utility just as an agent.

Question: If a utility has a PPA you discussed a concern that in the capacity market the PPA wouldn't clear and the utility would have to pay for capacity twice. However, in PJM if one has a contract for capacity they just bid it in the auction as a price taker. They bid it at zero because they've already paid for the capacity. Am I missing something?

Speaker 2: I think those were the old rules. Utilities were bidding at zero but with recent market mitigation measures they're required to bid at 5% of the cost of new entry. This is still a new issue so utilities are trying to get clarification on it.

Question: If a utility contract pays fixed capacity costs for a plant and flows through fuel cost, that obligation will be consolidated with the utility, correct?

Speaker 2: If it's a take or pay contract then there's a pecking order in FASB. The lease accounting standards go first, so if it's a fixed amount that you pay irrespective of what take or pay, then you would treat that as a capital lease and it would be on your balance sheet. It wouldn't be a full fledged consolidation and wouldn't be treated as a subsidiary.

Question: OK, if a power purchaser or generator is making a 25% return on their investment in that power plant it would seem that consolidating that income onto the utility's financial accounts would distort the utility perspective.

Speaker 2: Yes, it has to be a case by case evaluation. The circumstances of each individual transaction are examined and you look at how the risks are allocated between owners, equity investors and senior debt holders and see who bears the majority of the risks. In this situation, as you said, it may very well be that the utility does not come out bearing the majority of the risks. But that would be known only after the assessment is complete.

Speaker 3.

I'm going to discuss the competitive power supplier's perspective. The first question is why this issue is so important now? It's been around since 1992 but the last build-out that occurred through the 90s was largely IPPs, over three quarters of new generation. Most of that was on a merchant basis so PPAs were not as important. Currently, many state regulatory structures and markets have an open question as to whether utilities can self build again or must purchase power. PPAs and self-build questions get us to these questions.

Second, why care? It seems to be a technical issue, I never knew what it was until two years ago. However, it does go to the heart of the options and choices in viable wholesale competition. The rising cost environment is a big factor. CERA's index of power plant costs, from wind and nuclear to gas to coal, has more than doubled in eight years. It's up 70% in three years. A plant that was $1 billion is now $2.3

billion. Mounting costs are slowing the push for clean coal. Overruns occur in project builds, and even in projects still in the proposal process.

A recent report from Bernstein Research on traditionally regulated utilities shows three separate waves of double digit rate increases. Each wave is in double digits, not barely, but 15-40% each. There are three reasons: the first is fuel, the second is cap X to replace old retired plants, and the third is upcoming carbon legislation. There should be a competitive procurement option so that policy makers can compare all choices and not have something like this become a tilt against fairly evaluating purchasing from competitive suppliers.

Third is the concern for debt equivalency. GF Energy looked at this issue in a study three years ago, and power suppliers worked hard to transmit their concerns to the rating agencies. Rating agencies do this as a forward looking process strictly from the perspective of bond holders. The comparability argument makes sense. There could be a company that's all PPA and they would have a balance sheet that wouldn't be accurate compared to those who built.

However, comparability needs to be a two way street. There are clear benefits to PPAs. Ratings shouldn't be used in the resource procurement decision between self build and purchasing from a competitive supplier. Generally equivalency won't change the rating, but the percentage they derive is largely driven by the likelihood of recovery of the fixed payment. Utilities will sometimes say that an IPP bid looks great on paper but they add the imputed debt cost and this tilts the playing field.

Fourth, how are states actually responding on this? So far they are considering it carefully. A couple of quick examples. The Arkansas attorney general argued that "the debt equivalency argument provides the utility with a win-win at ratepayer expense either freezing out competition to its profit or increasing expense of equity to its profit." In Georgia, the utilities wanted to have a 30% adder and the Georgia commission staff sided with the competitive suppliers and said it should not be a factor. The utility withdrew the waiver request to the commission so it wouldn't become a precedent.

The Utah DPU faced the same concern and stated "at least as far as the cost of equity is concerned we find more evidence to support the notion that utility construction raises the cost of capital than non utility generation purchases do." The last and best example is in California which previously allowed a 20% adder. About six months ago the California commission decision said, "the evaluation of bids by PPAs and competitive solicitations includes a debt equivalency bid adder in an attempt to quantify potential risk presented by IPP projects while the evaluation of utility owned projects includes no similar up front bid adder even though utility owned projects present incremental risk to ratepayers and utility shareholders." These examples represent the right approach; they are encouraging. However, these cases need to be litigated on a repeated basis. We need to put the issue to rest.

Fifth, what is being done to address this concern? A variety of things: the FR report, materials on the EPSA's website address this issue, power suppliers have engaged with the rating agencies, and there's been extensive participation in forums such as HEPG, FERC, and NARUC.

The final question is what can regulators do? First, much of this problem is derived from whether or not the fixed payment is recoverable. The more the mechanism is automatic and recoverable, the percentage is zero, and the issue goes away, we don't have to worry about it. States with these kinds of mechanisms that are more automatic provide a model for other states. Second, states can not allow these issues to be considered in the resource procurement cases, as California correctly concluded. If this is not the case then states should ensure that comparability is a two way street. The benefits of PPAs need to fully accounted for and the risks of build options also need to be completely considered.

Speaker 4.

Credit analysis and accounting are attempts to make order out of chaos, it's not a simple process to describe a risk. It's certainly true that not many ratings are affected by these issues alone. Ratings agencies go through their calculations and then they say, does this really matter? How big is this relative to all the other things that a company is dealing with? The quantitative analyses look at the crossroads of financial and business risk and should delineate specific ratings but any given company could have an enormous number of anomalies and exceptions. Credit analysis is subjective.

Clearly, debt equivalency and accounting are not cut and dried, black and white questions. Power suppliers feel there is a barrier to competing on a level playing field. Utilities are also frustrated with being caught in the middle. They want to provide power to their customers at the lowest cost but they have different constituents with a variety of requirements. Rating agencies, their shareholders, regulators, suppliers. It's a real balancing act. Nonetheless, the reality is that debt imputation in the credit markets is a real cost of doing business. It can't be ignored.

Let's consider recent events in California. Their newest commissioner at the CPUC is John Bohn who arrived just as they were addressing imputed debt. He's formerly from Moody's. For four years they had been very skeptical about it, but had recently started to realize there was some value to it. However, the CPUC argued that the rating agencies were doing it wrong, and began doing different assessments. Bohn said, it's not wrong, there's no wrong or right in this; it's simply the way the rating agencies do it.

Power suppliers want to make sure that this is a cost that can be passed through at all times. However, although that would be nice, this is a debt equivalent, it is not entirely the risk of the cost getting passed through. Debt is a fixed obligation, there are dire consequences if a company won't pay it. Everybody assumes that the cost of debt will be passed through by the regulators. I've never seen regulators refuse to do that in 30 years. The rating agencies don't worry about that. With power purchase agreements there is a history of regulators sometimes saying no. In either case, it is a fixed obligation. That is the overarching issue for debt equivalence as far as rating agencies are concerned.

Thus, this issue is not going to go away, an ongoing conversation will continue. It would be nice if all stakeholders could deal with it with some consistency. Nonetheless, every circumstance is a little bit different. The best way to address it is to ensure that all parties understand the gravity of the issue and the reality of the financial pressure on a rating. It won't change a rating on its own, but if enough pressures build up on a company their rating can collapse. This has enormous consequences for customers and all constituents of a utility.

Risk is like energy, it can't be destroyed, it can only be changed in form. It moves around, it has to be somewhere. That is what the rating agencies are trying to describe, what the utilities are trying to get the regulators to recognize, and what the independent power industry would like to describe differently.

Moderator: Speaker 1 has some additional comments to add on to his earlier presentation.

Speaker 1: There are some other things that agencies have updated in their criteria. To the extent that a T&D [transmission and distribution] company has no control over the source of its power, for instance PSE&G, they're on the sidelines. The BGS [New Jersey basic generation service] auction takes place and they send the money and the power through. A rating agency would see no obligation for that company. In cases like that, and for Connecticut Light and Power or various national grid subsidiaries, an agency would not impute any debt at all. That was an important change.

Rating agencies are struggling to figure out how to deal with renewable energy contracts which have no capacity component. Wind, solar, even nuclear contracts, they are all-energy contracts. Some agencies believe there is a capacity payment hidden in that energy component. The company that enters this contract is getting its financial obligations paid through this payment stream from the off-taker. They are struggling with how to capture that. One option is to use the cost of a peaker as a proxy for the capacity payment. For instance, how much does it cost in this particular market to build that last unit? They would use that as a proxy to calculate the capacity component of an all-energy contract.

What about the mark to market? Companies in the northwest have cheap PPAs from basically free hydro power. Puget would enter into these contracts till the cows come home. Nonetheless the rating agencies still see these as an obligation for Puget to pay for them. Puget could sell them and make a lot of money, but regardless, rating agencies view it as a financial obligation.

The other area where an agency could impute zero debt is if there is actually legislation. There are a few jurisdictions where it is the law to enable utilities to recover their PPAs. The agencies will not impute debt in that circumstance.

Question: In a situation like PSE&G, they could break off a piece of the BGS load and have that bid solely by renewables. Would agencies treat that kind of contract the same way as the BGS overall or would they treat it differently?

Speaker 1: I don't know. There are good arguments to treat it the same. Renewable projects, SOX mandates, all that sort of thing, are public policy issues that have a different quality about them. They are public decisions that we as a people ought to be paying this not the utility. That would argue for leaving it alone. It would create a robust argument in any rating decision committee.

Question: It would be helpful if a rating agency weighed in on these issues in New Jersey as they are still being sorted out.

Moderator: This is an evolving process with the rating agencies as well.

Speaker 1: Parts of it, yes. The overall process is a done deal and has been for many years. Renewables and all-energy contracts are still being assessed by the agencies. that we have, that we still are getting our arms around. Even if rating agencies do move forward to impute renewable debt it de minimus currently because there are so few of them and they are such a small amount of overall portfolios. However, with 30 states that have substantial renewable portfolio standards it will become more meaningful.

Question: In the context of the California situation there was a question of imputing debt on a level playing field. How would that work, what is the conceptual model, and how should we think about this? What is the cap M for PPAs?

Speaker 3: Preferably it should not be part of the decision in resource procurement. It should be more in the cost of capital because it's an art, not a science. If there's imputed debt from a particular PPA, it doesn't mean that the rating or the cost of capital is changed. Otherwise, examples like Oklahoma occur. A power supplier there with a largely fixed price bid was competing against utility that's self building. Obviously there was a conflict of interest. The utility added a 20-30% to the power supplier's bid. So the bid from the competitive supplier was better. There was no evidence that the utility's costs or their rating were going to change; they just added it. Thankfully the self build was not even bid into the process and it was turned down for a variety of reasons.

If it is in the resource procurement it's not clear what needs to be included. The primary point is that it should be in the cost of capital proceeding and not tilt the resource procurement. There's no way to substantiate any real additional costs to the independent power producer's bid. Ultimately if it does get accounted for in resource procurement, then all the benefits of PPAs, and the risks inherent in self-build, will need to be incorporated but it's not clear what the formula is for that yet.

Question: The incentives are still skewed against PPAs because utilities can't mark up the price of purchased power, they can only pass it through. For utilities, the risks are only down side for imprudence disallowances and there is no potential up side for purchased power. If a utility builds they can have a return on it.

Further, debt imputation forces the utility to increase its equity component. So in essence the utility is able to earn a return on purchase power agreements when imputed debt is in place. Since this backhanded effect of making purchase power agreements profitable for utilities exists, to what extent does debt imputation create a more level playing field than without it? Is it a question of degree?

Speaker 2: That's one consideration for creating the more level playing field. To the extent a utility does react and its credit worthiness could be compromised. Then a utility could decide to increase its equity component and be allowed to earn on that. It's just another factor to weigh into the whole analysis and calculation. It's definitely something that would play into the analysis.

Speaker 4: This point is not recognized and does change the dynamics for the utility. They would rather earn a return on an asset than not. However, there are a lot of other risks that go into building that they don't have with PPAs. So if I'm a utility trying to make that choice and I want to avoid risk I'd rather earn some return on a PPA than take the risk of building something myself. People have not thought about it in that regard but it's a fair point.

Speaker 1: The PPA structure in this industry is hardly a business model that anyone would want to pursue. There's only down side for utilities. A few utilities get paid a fee for the work involved in getting power agreements for their retail customers. Almost no states bump up the allowed equity return in response to debt imputation at the rating agencies. Only California and Florida add a kicker to the equity return. I don't think there is a utility benefiting financially from PPAs or from regulators and debt imputation. There is a cost and that needs to be reflected in the overall cost of doing business.

Speaker 3: Oregon's the only state I know of that actively considered allowing the utility to earn a certain amount on the PPA. It seemed like a promising concept. That rule making has gone away but that's the only example I know of.

Question: What about Colorado?

Comment: Colorado has just opened an investigatory docket with a stem to stern review of cost of service regulation. They are considering how to set a utility's allowed earnings via rate based times rate of return formula which leads to a bias to build rate base to grow earnings, or something else. It's not as simple as earning a return on purchased power. That won't be the way it's implemented. It's not decoupling, it's a different matter. An alternate model is to figure out how to grow a utility's earnings based on a combination of the power they sell and what they do in energy efficiency. Those two would determine earnings level, instead of an all-in cost of capital times rate base. They need to see how ratings agencies will respond to that model.

Question: There is upward pressure on rates. In California, and other places soon, the disallowance of costs under these PPAs is a strong potential. Regulators are looking for any way to keep costs down. Utilities will need to be careful, even if they're prudent they may not be able to recover PPA associated costs. Companies might consider including clauses in their PPAs that allow termination if they don't receive full regulatory cost recovery. This shifts the risk of regulatory disallowance to the generator from the utility. How would power suppliers react to this approach? Second would it change the analysis by rating agencies?

Speaker 3: That's a new idea. There are also going to be potential disallowances on the self build side according to some analysis. Once a utility has entered into the PPA and the contract doesn't hold up it's a chill on all the investment. People should not go back on existing deals unless there's some compelling reason.

Question: I'm talking about new deals.
Speaker 3: It can be negotiated but it's a heavy burden. If nothing's recoverable and everything's up for grabs that doesn't help deal with the rising cost environment. The whole purpose of a PPA after a competitive process is to get the best deal. Contract modification would be resisted by power suppliers.

Question: Why should the utility bear that risk if it's not earning a return? The utility is just getting to buy the power for the privilege of passing the cost through dollar for dollar, why shouldn't that risk be on the IPP? [independent power producer] The utility bears the risk of prudence disallowance when it builds and that's perfectly appropriate rate making. However, if we're entering into a world where utilities are going to see a lot of disallowance they need to move away from risk that gives them no chance of return.

Speaker 3: Well, unless there's an actual example where these costs have been disallowed then a generic rule like this is not necessary.

Consider the broader picture. The alternative is for utilities to self build and that presumes those costs will be passed through with no cost overruns. Any of these individual issues should not be a deal breaker that precludes PPAs because of some new hypothetical. Utilities earn money on self build, they don't earn money on a PPA but it's for the regulators to decide whose interest should be predominant. Clearly the system is not designed so that only utilities make money.

Question: A prudent utility buyer will consider who ought to bear the risk of non-recovery of costs in a PPA. It should be the IPP because they are the ones who get to earn money. This strikes me as a fair balance of risk provision in a contract like that since the utility's not earning any return.

Speaker 1: Costs are certainly going up and the regulators are certainly going to be aggressive in prudence reviews and other areas. As far as the PPAs, the history is that they are passed through. Agencies don't call it debt equivalence for a reason. It's not equivalent to debt, it's debt-like in certain characteristics because it's a financial obligation but it's marked down 25 or 50%.

For a rating agency the concern would be that if they don't get cost recovery, and thus they cancel a PPA, they have to replace it with something. An uncertainty like that is never good for a rating agency.

For instance, Illinois just had its costs deemed as too expensive and so the utilities and the generators have ended up paying a penalty. There's another auction there in 2009 and it's not clear what will happen – costs will be very high and politicians may decide they are not appropriate again. As a result there are junk ratings on utilities in Illinois. It's ridiculous but that's the way it is. The uncertainty is a big negative.

Question: That's a very good point, thank you.

Question: For utilities this is a CEO level issue. They are trying to figure out where they are today and in the future. A third of the power comes from purchased power for the average utility. For some it's much more.

We need to move from the build versus buy question. For some utilities, it's a buy versus buy question. The big concern from agencies is whether it's a 5, 10, or 20 year contract, and the relative portion of fixed versus variable in that contract. That's an important consideration that hasn't been talked about enough.

A second questions is that some utilities are starting to ramp up quite a few PPAs the concern is when the debt imputation begins to kick in more forcefully, and directly, into the actual ratings. Where is the magic threshold? Utilities can't get a clear, transparent answer from the agencies. They need to know, is there a step function here, at what point does a little become too much, where's the straw that breaks the camel's back?

How do utilities think through this? How do they keep themselves from getting to that point where there's a major impact, like when debt equivalence first came about with PURPA contracts? That caught some companies off guard and progressed into rating downgrades for some. Debt imputation came about in PURPA contracts and caught utilities by surprise. So some companies are taking on more PPAs and the related costs are increasing a great deal – how can they make sure that they don't get surprised by extensive debt imputation down the road?

Speaker 4: One agency had a sliding scale for everything. They do a calculation at the two extremes of 0 and 100% and then try to determine where the company fits in between. There aren't guidelines or a formula for a utility to follow.

More than anything, the utilities need to simply ask. They should call them once a week, once a month, whatever it is. Make it a regular dialogue. Don't get frustrated with the agencies, simply ask them, they have an obligation to let you know.

Question: It's difficult for the agencies also because they're trying to keep track of how the regulatory landscape is changing. The regulators need to be part of the conversation loop as well.

Speaker 4: Absolutely, this is not a static discussion. It's something that has to be engaged in on a regular basis.

Speaker 1: I agree completely. It's difficult for the agencies to provide any clear and consistent guidelines. Further, a company that's increasing PPAs will have at least some impact at some point. Some companies may have around 10% of their debt being imputed and that could go up.

Question: I'm glad the power suppliers are hearing that point.

Speaker 1: The scenario you describe with high levels of PPAs and increasing amounts of PPAs is an exception. It will eventually have an effect on the rating, especially if they're not growing the rest of the business.

Speaker 3: If the utility were to build the plant instead of buy from a PPA what would happen to the debt from the plant that they built?

Speaker 1: They would be issuing equity as well so there'd be a balance there. They'd be generating a cash stream that goes to the overall general corporate welfare of the company. That is not the case with a PPA. A PPA is a cost pass through for a utility, it doesn't benefit the company at all. That's the difference.

Question: Let's return to the California decision of last December. All the IOUs in California have filed for rehearing. It's not a done deal. Let's consider that the industry is looking at an enormous need for new investment, at least a trillion dollars and yet over the last ten years the average credit rating of regulated electric utilities has declined. Those two trends are on a collision course. It's in the public interest to protect the credit of the electric utilities. Very much in the public interest.

California has said they will not worry about this while they make resource decisions, they will deal with the cost of capital part in the next rate case. That's troubling. A first line of defense should be capturing this transfer when you look at the tradeoff. I'd like your comments.

Speaker 1: Certainly compared to 1999 the ratings are down because there was the whole turmoil of that period. But in the last few years there has been a fair amount of stability overall.
Question: This data is from '97 to 2007. It is substantially the regulated utilities.

Speaker 1: The regulated and unregulated are consolidated.

Question: OK. It's a fair statement to say that credit has weakened in the industry and that's not a good thing.

Speaker 1: Right. Maybe a notch. The average rating of a regulated utility is probably about triple B plus, historically it's been more like A minus. Maybe A. So it's a notch, maybe two. There's a fair amount of stability right now and for the next couple of years. 86% of the entire industry including the merchants is investment grade. Pretty solid, pretty good. We're entering an uncertain period of time with a pretty healthy industry. What that pie chart is going to look like in three to five years is a different story.

Question: 20-30 % of the industry are just at investment grade. Those folks, and their policy makers need to be very sensitive to this. They don't need to get pushed below investment grade.

Speaker 4: A recent Moody's annual industry report stated there has been relative stability in the industry over the last couple of years and that is a credit negative because of what's coming.

Moderator: There's a good paper with an objective analysis of debt imputation issues being made available to FERC and to regulators put out by The Brattle Group for the Edison Electric Institute.

Question: What should a policy person do? Power producers may try to persuade analysts to consider other issues in debt imputation. Analysts still need to look at the risks properly. I find it puzzling if regulators are disregarding this information. They should take it into account. It's not definitive. It's like every other decision that a regulator makes. They take all the information into account. One new item is that all other things being equal a PPA has a little hit on the balance sheet. It's not the only question. There's diversity of supply and other issues that might overcome the negative. It shouldn't be ignored however.

Speaker 3: Power producers understand that. They just want to understand what the analysts do, and how they do it, and to have some transparency. Recently, some companies, when they've revised the criteria, they've allowed for comments like a regulatory rule making.

Second, what should regulators use it for and what context? They need to consider the benefits of PPAs, and the risks. The FERC NARUC dialogue last July took a good look at this. PPAs and competitive procurement are both needed. There are examples where agencies have expressly noted the benefits of PPAs. It's important to have a conversation and a balance. That gives the public assurance that it's been addressed fairly in a rising cost environment.

Speaker 1: That is absolutely right. The analysts also need dialogue with regulators and that's harder. Unfortunately the average tenure of a regulator is three years or so. They should feel comfortable calling the agencies. Agencies do things that leave regulators scratching their heads. There are timing issues. They'll issue a press release right smack in the middle of a major hearing or rate case. The rating agency world is a very narrow one. They focus on one aspect of the capital markets; fixed income obligations for utilities. They regulators should feel free to reach out to the rating agencies.

Question: I'd like to challenge this notion that regulators simply need to reflect the reality of agencies' actions. Regulators may be at the source of the problem. Let me just illustrate this. If a utility has imputed debt issues coming from a PPA and gets a hit on the balance sheet, that hit is a reflection of the ultimate recovery risk, right? If it's not recoverable that is worrisome to the credit agencies.

However, if I understand this correctly, the same recovery risk is not applied to self build assets. The regulator doesn't take the asset value of a built plant under rate base, discount that by 20 or 50%, or take the future expectation of cash flows from that and discount it for the same recovery risk. The PPA has a recovery risk that's factored into the rating risk of a company's balance sheet and obligations but the risk from a self build component is not accounted for. Regulators really need to look at both sets of risks when they are making decisions between PPAs and self-build options. Yet the rating agencies seem to impute a bias saying the PPA is more likely to have a recovery risk than the self build option. Am I missing something here? If the bias is there, isn't that sort of a regulatory commissioner issue?

Speaker 1: I'd say it's regulatory in management. There is a business risk profile and a financial risk profile for rating agencies. When it comes to building a plant it is a risky proposition that a company has undertaken. They will not have the same business profile that a company that is not building, or is buying PPAs. It's not uncommon for agencies to downgrade a company as it goes through a stressful period of building a major coal plant, especially if there are any concerns or issues. They may not get recovery on parts of the plant, especially if it's over budget or delayed.

Question: Under the PPA there is no construction risk whatsoever.

Speaker 1: That's right.

Question: Let's assume the plant can be built overnight like the PPA gets put in place over night and that the construction risk doesn't exist. Is there a bias then that once the plant is in and gets constructed as planned that the recovery issue under standard rates is not an issue any more, for the agency's purposes of rating?

Speaker 1: There may be $1 billion more of debt on the balance sheet that has to be serviced.

Question: There's debt on the balance sheet but there's an asset value; the plant has a future cash flow. An agency won't take a discount on the future cash flows.

Speaker 1: No, they look at the stream of revenues that the regulators have allowed the company to generate, and consider it over the new level of debt.

Question: They have allowed the revenue, but a year later they may disallow it those revenues right? Like they would disallow PPA recovery, right? That's why I don't see why there's a difference there in the imputed risk profile, of future regulatory pass through.

Speaker 1: I don't understand the question. The agency incorporate the risks of owning and operating a plant into the overall business profile. A company with that business profile will be weaker than a T&D company. It puts greater pressure on that company's financial metrics to be stronger, to perform better for any rating category. A company that is just buying the power through PPAs doesn't have those risks at all. A company may not be able to recover all of its costs, through construction or through the operation of a plant. Whole plants have been known to go down for a long time. Nukes even go down from time to time and not all the replacement costs are allowed to be recovered because it's deemed that the plant should not have gone down, that the management was imprudent for allowing it to go down.

Question: But the original capital costs are, for the agencies, deemed completely recoverable under all circumstances?

Speaker 1: If there was a write-off, yes.

Question: I'm not quite getting it. A balance sheet has debt and assets. The assets are backed, either a book value or built up value based on the future projections of cash flows that are coming from the rate base against that asset. There's an asset value there that goes against the balance sheet.

A regulator may decided at a later date that they don't like the rates. If it's PPAs they can invalidate the contract or forfeit the recovery. They can also invalidate the pass through of the original capital costs of a power plant? Or are regulators biased? Once something is built and they approved the costs, therefore they will never go back. That's a sort of a bias that regulators have that favors self build versus PPAs.

Speaker 1: Once a plant is built in rate base something typically has to go wrong for the plant to be examined again. Once it's in rate base the revenue stream associated with the plant is going to be available to the company, and the agencies will reflect that.

Question: But on the PPA side once the contract is approved the agencies don't take that same approach. The PPA contract has been approved. It's well known capital, effective cost streams.

Speaker 1: Again, the company is issued debt, the company's financial metrics have now changed because of the company's issuance of debt. It's real, it's on the balance sheet, it has to be serviced, and they incorporate it into their financial metrics. It's a fixed obligation with no asset backing it.

Speaker 3: Historically, have there been more disallowances on PPAs or on self builds? Are they about the same? Why aren't they treated in a similar fashion?

Speaker 1: There are different dynamics at work. Construction risk which you don't have on the PPA, then operating risk. It's a very different profile.

Question: If a PPA has been approved for its whole duration, why is there a risk it would be disallowed? The only risk is if the regulators are changing their minds.

Speaker 1: Right. The ratings speak to the risk associated with satisfying financial obligations. Simply because the regulators blessed it does not mean it won't go away or that they may not change their minds. If it's securitized, that's a different situation. Otherwise, things change, economic situations, operational situations; and they affect that revenue stream.

Question: The same changes can happen with a power plant. For instance, a regulated utility builds a power plant that's gas and the price of gas goes through the roof. The regulators won't disallow the original capital cost of the power plant. Yet the agencies are saying that regulators would do that with a PPA.

Speaker 1: It's a matter of scale too. The amount of debt they're adding back for any given PPA is minimal. Only a few companies have a portfolio where it's meaningful.

Question: Consider that one is calculating an imputed debt amount based on the future cash obligations that the utility must make and adjusting the credit rating downward increasing the total debt on the balance sheet. The corollary is that this would increase the credit rating potentially for the independent power company, the counter party to that PPA. Theoretically that should improve the cash flow to debt metrics, and lower their cost of capital. I don't think it's a zero sum game necessarily but I am looking for symmetry in the approach. Has an agency has applied these issues in a symmetrical way and whether suppliers or counter parties have benefited?

Speaker 1: There is no such thing as a credit cap and trade market. [LAUGHTER] There's not a limited universe of credit. The credit quality of a supplier will benefit from having entered into a PPA, if it's got a strong counter party on the side.

Question: Would the agencies reduce the supplier's outstanding debt by an imputed calculation? Does the imputed debt that comes in on the utility side get balanced as a symmetrical calculation by the imputed net present value of that cash flow for the power supplier and reduce the debt outstanding on a power supplier's balance sheet?

Speaker 1: No, they don't. It's an analytical tool. Not an accounting convention at all.

Speaker 1: A power supplier would benefit clearly in terms of credit quality because they've entered into a counter party of credit worthy features.

Question: So the agencies are skewing the competitive contest for procurement because they're increasing the utility's cost of capital through imputed debt on a PPA but not improving the credit rating related to the imputed debt that is being transferred from the power supplier's balance sheet.

Speaker 1: They are not reducing the amount of debt, that is correct. An independent supplier will benefit from that contract, maybe even to the point that it has an improvement in its credit rating. It is not a zero sum analysis. They are trying to get to the economic reality as it affects each company. The two will not be in balance. The credit analysis is simply the economic reality underlying the audited statements, the risks and financial obligations of this company. A credit analysis is simply a tool.

Question: I understand. It simply seems that if one party is gaining imputed debt from the PPA and the other party is gaining a credit benefit as you've acknowledged, then they should be receiving that benefit more formally, as a form of imputed credit. Otherwise the analysts are changing the inherent quality of the competitive contest on procurement.

Moderator: This issue needs clarity.

Speaker 1: There's just disagreement.

Speaker 2: But don't the credit agencies make a qualitative adjustment in favor of IPPs because they have assurance of revenue stream? Perhaps not the same calculation as imputed debt but certainly something, as you alluded to earlier?

Speaker 1: Yes, that's what I was trying to say. You said it better, thank you.

Speaker 3: It's helpful to have the question raised and broaden the discussion. We should be concerned about credit ratings of utilities but there are also the broadest possible pool of investors. Some utilities identified in the Bernstein report will have strong headwinds. They are saying competitive procurement is unnecessary. They don't want to discuss debt equivalency because the credit of the competitive suppliers is such that they can't participate. A power supplier with more PPAs on the competitive side would probably have a better risk profile than somebody who was completely merchant, correct? It's just not analyzed in exactly the same manner.

Question: I'd like to clarify one issue. Any time a contract or a plant is out of the money there is risk of recovery, notwithstanding that it's booked, passed a prudence review if it's a nuclear plant, and/or that the a Commission made a utility sign contracts at prices they set for you. If they're out of the money they've got a problem. This is demonstrated particularly well with renewable contracts which are popular but more highly priced. Some utilities and commissions are considering building generation or doing long term contracts, not just spot prices or 1-3 year contracts. I'm an advocate of an intermediate position. There are intermediate courses including layering and laddering contracts of different lengths.

Clearly credit analysis is not procurement. So a utility with no generation that wants to hedge, especially for smaller customers, has to see debt equivalency as a legitimate issue. However, there are risks associated with self builds and contracts – both have to be considered carefully in the resource procurement process. There's certainly a concern if debt is only being imputed for PPAs and not for other activities. However, there should be no problem if the evaluation is as comprehensive as it can be.

Speaker 3: The only way this could be done is if everything is changed in the procurement process. The change can't be made in isolation. For instance if the procurement decisions were not made by the utility but by a neutral third party. The utility is also the judge and the jury making the decision under the current system. Federal or state rules that addressed procurement as an independent decision would be worth considering. The problem is that there are incentives for a utility to self-build for their own benefit, not necessarily for the public benefit – they can make more money. On top of this the imputed debt is added in and that only helps a utility's case, even though the other speakers have mentioned that it's a very minimal effect in most cases.

A supplier almost always performs under these contracts, which is why the utility is going to have the obligation. If there was a spotty record on performing it wouldn't be as much of an issue. The FERC NARUC dialogue should be the forum to put this all together. Most states don't require competitive procurement, where they do waivers are sought. It's not a fair system.

A comprehensive discussion on reform allows for putting everything on the table but most states that aren't in the organized markets have utilities that tend to pick themselves. It's bad for independent power suppliers, and for having an arm's length transaction and a transparent process with choices. The Bernstein report really underscores these problems.

Question: I'd like to discuss organized capacity markets. In California they are discussing adoption of a four year forward market where suppliers could get one year capacity contracts four years in advance and new suppliers, or suppliers of a new generation project, could get a fixed price commitment for ten years. Some assert that the financial consequences of these capacity contracts would not show up on the balance sheet of the load serving entities that will be paying for the capacity four years later. Does the panel agree that this is a valid assertion. Second, could this change in the future?

Speaker 1: These are one year contracts out four years?

Question: Yes. Procured through a centralized capacity market, locational one price auction, run by the California ISO.

Speaker 1: Would this end up on the balance sheet of the load serving entity?

Question: Right. Some argue that the FERC tariff would address this risk and that rating agencies would not impute any adverse financial consequences to the utilities.

Speaker 1: That's probably accurate. I can't say for sure but it sounds appropriate.

Speaker 3: New England allows that, correct? PJM doesn't but in New England you can get a commitment for new build beyond the one year. There's an issue of how does one treat it for the one year but for five year commitments in New England it's a live issue now.

Speaker 2: From a financial reporting and consolidation perspective it's useful to have an organized capacity market. It's being proposed in New York. It would mitigate the risk of having additional debt commitments on the balance sheet.

Question/Comment: First, I'd like to clarify how the New England capacity market works. There's as much as a five year commitment made to new capacity through that market. However, from the LSE's [load serving entity's] perspective they don't have any obligation until the delivery month. It's really the ISO New England making the commitment through its tariff. So that cost is spread out to all the tariff load in New England. Since they're mostly in a retail access region and they don't know who's going to be serving the load in five years. It was purposely designed so it wouldn't show up as an obligation until you the delivery month.

My question concerns a new risk out there. This is the risk of a new but unknown carbon constraint or carbon cost. Somebody has to take that risk and from the credit agency perspective how are they evaluating that risk?

Speaker 1: They know it's there. They know the most likely candidates to be affected but it's too premature for them to begin to take any rating actions. They could indentify the companies that will be most affected but beyond that there are still far too many unknowns.

Speaker 3: It's almost impossible. No one knows if the allowances will be free and if so, in what way – input or output based? Other bills would auction the vast majority of allowances and that has very different implications. There's far too many uncertainties to put into a fairly certain rating. Companies do want to end the uncertainty. They'll all fight and scrap among themselves and with others about what the details should be but the uncertainty is just putting a chill over everything. However, the legislation could take a long time, 2010 or 2009 at best, but I think more likely 2011, 2012. It will be a ferocious debate with enormous regional splits.

Speaker 1: The near term outlook for the industry is pretty stable. Past three years it begins to get real negative.

Speaker 4: RGGI's [Regional Greenhouse Gas Initiative's] going live within this year potentially, and the agencies are still taking a wait and see posture.

Speaker 3: Some people have run scenarios. One was a takeoff on *An Inconvenient Truth* called the Inconvenient Math. I think it's publicly available today from Credit Suisse. This analyst looked plant by plant, company by company and ran different scenarios based on assumed carbon prices. Some of these scenarios were quite unpleasant for some power suppliers. The Bernstein report does something similar with less detail.

Question: Does switching the risk over to the seller of the PPA from the utility if the costs don't get passed through raise the cost of the PPA? Am I wrong? Is it more complex than that or does it raise the cost by shifting the risk?

Speaker 3: I believe you're right.

Speaker 4: It comes down to what investors are going to be comfortable with. For the builder to attract capital they will have to pay more if they don't have certainty.

Speaker 1: If it raises the cost it's because the cost now hides the risk that's being imposed on shareholders as a buyer which is not offset by any return. So it should be higher. And on the fixed income side the same holds true. It's a level of uncertainty that had not been there before.

Question: Nuclear and clean coal are very expensive new technologies that will require longer term contracts to get built. They will have greater risk. Current commissions cannot ensure what future commissions do. For longer term contracts is securitization an option that states should be looking at?

Speaker 1: Rating agencies don't care, they'll just analyze the risk. I'm not aware of states considering securitization. The stranded asset deals should have had more of that I think. From a cost point of view it would lower the overall cost. I'd think that commissions and bankers would all be considering this.

Speaker 3: Yes, it just seems from a customer point of view that securitization by reducing the possible debt imputation could be a benefit to consumers by not having the potential impacts on ratings as well as lowering just the total net cost to consumers.

Question: Rating agencies impute debt associated with PPAs to compare the risks of utilities that build with utilities that buy. Some have indicated that when a utility is making a planning decision between building and buying they shouldn't consider the imputed debt because building has risks as well.

Let's consider a specific example. Let's say an large utility were looking to build a plant as opposed to buying. If they were to buy it's clear that the agencies would impute debt associated with it. If they were building would the agencies be assigning any sort of comparable risk? If not then utilities should be considering the difference between building and buying. Would a company that already has significant amounts of PPAs be considered more risky if they try to build? If they add more PPAs then they would they be considered more risky?

Speaker 1: Analysts believe that a company is incurring incremental risk when they go down a self build program. I don't know if I can just say yes or no to the question. If a company has built terrific plants with great regulatory support and has recovery the build option increases the risk but not so significantly that an analyst would even consider changing the outlook on the company. It really just depends on all the different elements that go into the riskiness that a particular company has assumed by going down this route and what regulatory mechanisms you have been able to structure with your regulators as far as the timeliness of the recovery. And to the extent that there are excess costs, how those are managed too.

Question: OK, but consider a large utility with a large purchase power portfolio that needs substantial increases in either purchased power or other means of fulfilling their portfolio in the future. What I'm hearing is that if they were to build that would increase risk as compared to increasing more purchased power, correct?

Speaker 1: They look at diversity of supply as well too. To the extent that the utility is getting out of balance one way or the other the analysts might say that the build option is decreasing risk. They would have to look and see how the utility manages the construction and all that.

Question: OK, so a utility in a situation like that might consider some building to decrease their risk because additional buying and PPAs really does result in some imputed debt. That should be considered in the planning decision by the utility.

Speaker 3: The difficulty is how does the utility do that without tilting the overall decision? This has been argued and/or litigated in some commissions and they've made good decisions so far. The question is how it can all be done without tilting the procurement process. The commissions say they shouldn't consider it because what the utility does for legitimate reasons results in a number. If they could figure out how to quantify everything else that's being described, not just the benefit from building more, that would be worth considering. All the other risks and benefits have to be quantified similarly, and probably with a neutral third party to make the decision too. The IPPs have objected because that's not how it's been done. It's been used as an absolute shield or slam the door mechanism to go with a build option. Their approach has been to say that a complete and fair approach is needed, or that such imputed debt mechanisms don't get considered unless everything else does. So far the weight of the state decisions is to ensure that imputed debt is not a bar to competitive procurement. California's decision was in the mainstream of every other state that's ruled on the matter.

Speaker 1: It depends a lot on what's being built. A medium level gas plant is not particularly risky. A nuclear plant is obviously completely different. There are a handful of coals being considered.

Question: No, there's nuclear.

Speaker 1: Not for the next several years.

Question: This is a question for a commentator and the panel. One early comment suggested that if a utility negotiates a contract which says if it's out of the money going forward because the regulator disallows it, the contract is null and void. That seems like the regulator says we paid a higher price for this contract up front because we imposed the risk on the supplier. We paid for the right to now execute the option in order to get out of this contract because we don't want to pay this high price. How do you get out of that conundrum?

Commentator: All I was suggesting was that if a contract is not approved by the state regulator, because it's found to be an imprudent purchase, the buyer has an escape clause to get out of the contract. This sets up a dynamic so that shareholders are not implicitly subsidizing the price in the contract and taking on risk. This is perfectly appropriate. It puts the risk in the right place so that risk of disallowance is priced into the contract, as it should be, rather than being hidden and borne by shareholders of the buyer. The utility buyer is really just a pass through entity in this situation. There's no moral hazard.

This means that the state will take a hard look at whether it wants to disapprove the contract because it can't just drop the costs on the utility shareholders. It also incents a potential renegotiation of the contract with the supplier because the shareholders are now being asked to bear risk. This just puts the risk in the right place.

Question: I think this is called disagreeing. I still see problems in this approach.