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**Rapporteur's Summary\*****Session One.****Regulatory-Market Arbitrage: From Rate Base to Market and Back Again**

*At the time of electricity market restructuring, many vertically integrated utilities sold their generating assets, or took them out of rate base and made them market-based assets. Many of these companies recovered "stranded asset" value, namely the difference between the remaining book value and the estimated market value of those facilities. The actual market value of the plants has fluctuated over time. Recently, particularly in regard to coal and nuclear facilities, the value of those plants has declined. Some utilities seek either a return of those plants to rate base or a new long-term contract that is an economic equivalent. The benefits of such arrangements are cited to include providing a consumer hedge against price volatility, added levels of reliability, and resource diversity that has long term value. What do such movements of assets say about the viability of competitive markets? If the consumers benefits of price hedging, resource diversity, and so on are there what arrangements provide the most efficient way to obtain them? Should consumers get some credit for having already paid (in full or in part) either when they were in rate base, or through stranded asset payments? What effect, if any, will such arrangements have on retail choice? At the federal regulatory level, what impacts do such proposed contracts have on electricity energy and capacity markets? What impact should such arrangements have market pricing authority?*

*Moderator:* I really appreciate the opportunity to moderate this panel. I'm going to make some general opening remarks where I will try very hard to be as balanced as possible and then turn to the panelists. In part, I'm going to be reflecting back on how I thought about things when I was at FERC and how I think about things now. And fortunately there's not a big difference between the two. But one view I had at FERC was that

markets can't work if buyers can flip between the lower of cost or market and also that markets can't work if sellers can flip between the higher of costs or market.

When I was Chairman there were repeated efforts by buyers in some states to choose between the lower of cost or market. And FERC consistently rejected those efforts. One reason I

\* HEPG sessions are off the record. The Rapporteur's Summary captures the ideas of the session without identifying the discussants. Participant comments have been edited for clarity and readability.

actually never felt very guilty about that was that I felt that doing otherwise would doom markets to failure and that also I had a conviction that if generators ever tried to flip between the higher of costs or market that FERC would resist those efforts just as much.

But I think it raises two different worldviews looking at the current situation where you see a lot of uneconomic generation. From one perspective you can say that the retirement or potential retirement of this generation is the beautiful natural result of markets operating perfectly, reacting to low gas prices, or you could view it as a tragedy, and see it as the product of flawed market rules. Now, if you think the latter, then I think we certainly need to focus on fixing those rules so that this irrational result doesn't occur. But if you think that the first is true, that it actually is a beautiful and natural result of markets working properly, then we probably should just offer sympathy and call it day. I can say that because NextEra actually doesn't really own any of that generation so I can be fairly academic about that. But generation owners in multiple states are certainly weighing in. They believe that the current situation is the result of flawed market rules. And in some cases they're seeking the refuge of cost based pricing as a reaction to market failure.

Now, the most direct path towards this refuge would be reintegration--utility acquisition of generation that was spun out in the past. I personally have doubts about the viability of that approach since I think it would naturally result in demands by states and consumer groups for some kind of windfall profits, credits for revenues that were earned during a period when that generation was spun out.

But most of these approaches really take more of an indirect tack and they seek cost based pricing

through contracts or RMR's (reliability must-run contracts), and this indirect approach may be preferred because it's seen as more viable. It also may be preferred because it's a way to preserve the option of choosing market prices when market prices do recover.

Now other approaches to finding a safe haven for uneconomic generation involve clean energy standards and capacity market reforms. The clean energy standard is frequently characterized as merely an extension of existing RPSes. But the impacts of clean energy standards on wholesale markets are very different. I mean, state RPS's actually have a very slight, negligible impact on capacity markets because of the low capacity factor of wind and solar. But a CES program involving nuclear plants would actually have a really significant impact on capacity markets. So it really isn't just the same thing or a slight extension.

Now, some of the recent capacity market reforms appeared designed at least as much around supporting uneconomic generation as assuring reliability. And I personally think the PJM capacity transition, with PJM increasing payments to already committed resources, was really designed to maximize transfers to uneconomic nuclear plants, rather than ensuring performance at a reasonable cost. There have been state efforts over a number of years in both PJM and New England to suppress wholesale prices, some of which have been successful, but other state actions seem designed to achieve a particular policy goal rather than simply lowering wholesale prices, although that could be a side effect or collateral damage from that state policy.

So to me this panel revolves around some threshold questions. Is the retirement of uneconomic generation of beautiful and natural result of low gas prices, or is it the tragic

consequence of flawed market rules? Do we want to continue to rely on competition as much as possible and on wholesale power markets? If we want to go back, can we go back? Is reintegration even possible? If not, even if it might be preferred, we have no choice but to make competitive markets work. And what is the proper FERC/state role over resources? Should FERC accommodate facedly legitimate state policy goals even when there's market harm? And will FERC protect the integrity of wholesale power markets in the face of threats posed by buyer market power, state subsidized resources, price suppression, and attempts by generators to secure the higher of costs to market?

**Speaker 1.**

My company has got two businesses. We've got the regulated utility business down South, and then we've got our unregulated wholesale business, including nuclear generation capacity, a little bit of wind and a little bit of coal.

You know that we made a number of announcements here recently relative to shutting down a number of nuclear plants in the Northeast that includes Vermont, Yankee Pilgrim and Fitzpatrick. As you look at the nuclear fleet, I think everyone knows it provides about 20 percent of the overall power supply to the U.S. We've got a little less than a 100 different reactors at 62 sites. What you see here is just an outline of where we've got plants in regulated markets and where we have plants in unregulated or competitive markets. And I think everyone's probably well aware of the fact that nuclear provides about 60 percent of the carbon free generation across the U.S. and runs at very high capacity factors.

So as you look at the sources of revenue for a nuclear plant in the Northeast markets, you kind of break it down to capacity and energy. And so

as we looked at the decisions we had to make across our portfolio, we have seen some improvement in the capacity markets, both in both in New York and New England. The problem is that is a fairly small contributor to the overall revenue stream for a baseload resource. So as we looked at our ongoing economics of these plants and made the decisions to shut them down, energy price was a key consideration in that decision.

This chart just kind of lays out what the different breakdown of revenue streams are by technology (nuclear is the technology that gets the greatest share of its revenue from energy payments). And this next chart, showing day ahead and forward power prices, is the environment that we've been dealing with over the past 10 years or so, and as we look out into the future. And the markets from our perspective worked very well when the price of natural gas was high, but even in the mid-range, when prices moderated after the peak in 2008, we were still able to at least cover our costs on most of our plants. However, most recently, as we look into the future, we're significantly impacted by the lower cost natural gas due to the Marcellus play in the Northeast, and we're looking at much lower forward prices than we've ever experienced before.

When you take that and you look at it from a business perspective, you are simply in a situation where the forward prices don't cover your cash cost. And so we provided a little bit of a breakdown for merchant nuclear--you know, what that looks like, what that breakdown of costs is, but in general, the plants that we have up in the Northeast, especially single unit sites, their cost is somewhere in the 50 dollar plus a megawatt hour range, and what we're seeing is revenues in the high \$30's, low \$40's. And so we have a significant gap to fill. We're not the only ones in this situation.

I mean, obviously we've got a number of nukes that have made shutdown announcements, some of them for operational and mechanical issues, but a lot of them also for market issues.

One of the things that we think is important from a policy perspective is to consider the benefit of nuclear generation in achieving environmental goals. Whether it's the Clean Power Plan, or whatever it ends up to be, the loss of existing nuclear generation is a significant consideration from a national perspective. And what we see, time after time, is that markets tend to assume that existing nuclear units are going to continue to run, and that will be part of the equation in terms of how folks can meet their CPP. In fact, New York has just come to that realization with their proposed CES where they want to actually subsidize some specific merchant nuclear plants in the Northeast in order to save those plants and in order to meet their CPP goals.

I will tell you that while we support putting a price on carbon, we don't necessarily support the one off policy of picking winners and losers as it relates to a CES that basically is going to bridge the difference between cost and market. We think that it should be a market-based approach that values carbon across the board and provides value from that attribute to all resources that provide that benefit.

So what we're seeing is kind of across the board. We're seeing declining reserve margins across the U.S. I would argue that competitive markets have worked fairly well, perhaps, in the past because you had excess supply that was created by the inefficiencies of integrated resource planning by utility. However, I think we've gone too far. We no longer have any long term objectives as we think about what we want to accomplish in these markets. And as a result of economics making it simply uneconomic to

continue to invest capital in some of these businesses, we're seeing now where we're getting to the point where you're getting closer and closer to reserve margins. In fact you know, in some cases we may be projected to fall below that. So this is a real test for how markets function when you are in the situation where you've got to add incremental resources in order to meet the needs of your customers. And, as such, we're going to absolutely see an increase in price, because we'll be adding new resources while others are shutting down.

This chart is just a simple example of you know, the basic argument that we've been trying to make to policy makers. So, depending on where you sit across the U.S. you're range of wholesale energy prices needed to sustain existing nuclear is 30 to 60 dollars. Assuming you're having to add incremental resources to replace that lost capacity, you can see that in a lot of cases that capacity can be more expensive than letting that unit run. And so in the long run we believe that as you deplete the merchant nuclear fleet, what you're going to see is a number of things. You're going to see less reliability, because you've got less diversity. You're actually going to see higher costs to the end use customers over time. And you're going to subject yourself to a lot more price volatility if you're going to rely largely on natural gas in the long run.

So our perspective is that you've got to pick one or the other in terms of these markets. Down South, obviously, we have a more traditional vertically integrated utility. We get compensated for prudent cost and allowed to earn a reasonable return. We're fine with operating in a market that's truly a market, but what we see is that we don't truly have a market because it's really a hybrid. You've got a lot of actions by a lot of different people. We don't think the market pricing structure for energy price is necessarily fair or appropriate, and you've got a

lot of different things that are impacting that , from RPS to one off contracts that governments may decide make sense.

But let me make it clear. We're to the point now where we have to rely on the states, and people are in survival modes. So they're doing everything they can just to keep the plants operating. We've made the decision to shut down the plants, because we believe in markets, but quite frankly a lot of folks are put in a situation where they have no other choice and they look to the state for alternatives.

So this just kind of gives our perspective of how things come out in the long run. So you start out with a market that's over supplied. You've got a lot of out of market interventions. You've got maybe price structures that are not fair, so you see lower market prices. Eventually you'll drive a number of generators out of that market. Once you go below your required reserve margins, you're going to have to add incremental higher cost resources. And so we think in the long run, again, that's more expensive, and it has reliability and environmental impacts. With some changes in market, from a market reform perspective, such as revised energy price formation, improved capacity markets, putting an attribute on carbon, you actually will have more stable and lower prices as you go into the future.

So we don't think that there's any silver bullet here. You know, somebody asked me whether there is one thing that would save nuclear plants? No. I mean, it's really tough in a low gas price environment. But as we were making decisions to shut down plants, we saw really little or no progress from a broader federal perspective to address some of the matters that I just mentioned, and we couldn't see a way out with the states, and we were not about to ask for a special contract, because that really kind of

goes against our principles. But we certainly understand why people do that in order to keep the resource mix they need to meet their long term objectives. So I guess in the end you really need to have a market that's a true market, and that values all resources based on the attributes they provide. You'll have some that survive, some that don't. We understand that, but right now a hybrid market is just not a market that we're willing to invest in anymore. Thank you.

**Speaker 2.**

Thank you. I appreciate it and thanks to the Harvard Energy Policy Group for the invitation. I'm speaking from the perspective of an electric utility company dedicated to safety, reliability and operational excellence. We have 10 regulated distribution companies. Our operating companies own more than 268,000 miles of distribution lines. Our transmission subsidiaries operate three regional transmission operations centers and approximately 24,000 miles of transmission lines. Here's a picture of our generation fleet. It controls nearly 17,000 megawatts of capacity from a diversified mix of non-admitting nuclear, scrubbed coal, natural gas, hydro and contracted wind and solar resources including 1900 megawatts of renewable energy. In fact we're one of the largest providers of wind energy in the region with sales of more than one million megawatt hours per year of wind generation.

I'd like you to note that we have 3800 megawatts of regulated generation--generation that participates in PJM's energy and capacity markets. Regulated generation is not excluded from PJM. In fact, nearly 30 percent of the generation in PJM is subject to traditional rate regulation, cost based regulation. Like many others, we face challenging conditions in energy and capacity markets. Speaker 1 spoke to it. We're all being squeezed just a bit. Low natural gas prices and low power prices are putting

stress on the market. And certain market design flaws are exacerbating already challenging markets. Now, these design flaws aren't new. But generators weren't as concerned about them in 2008 when power prices were at record highs. However, today's low market prices are forcing generators, utilities, regulators, legislators, all of us, to think hard about how best to move forward and how best to serve customers long term.

Now, we acknowledge and we appreciate the fact that people are trying to fix the market. I think we're part of that solution. And capacity performance was clearly a step in the right direction; however, there have been more than 25 attempts to fix the capacity markets in PJM alone over the past 10 years, and we're still not there. And time is running out for certain generators. Nuclear plants (as Speaker 1 mentioned) with useful life remaining are being closed. If the government's goal is to move forward with clean energy, we can't let another nuclear plant close.

We all face difficulty reconciling capacity markets that provide a single year price with significant capital investments that require multiple years of revenue strings. Historical market volatility makes planning for the future very difficult. Consider that in a span of four years we've seen capacity payments range from \$16.00 to \$357.00 per megawatt day in PJM. And let's not forget the purpose of capacity markets. They're supposed to provide the missing money. Despite this design concept, capacity markets in PJM have cleared as low as six percent of the net CONE (cost of new entry) value (the proxy value for replacement resources). And prices have not approached net CONE at any point in the past eight auctions. So the missing money is still missing.

Capacity markets that only provide a single year price are an economic, financial, and practical problem for all of us. It's an issue we need to think about and address. Without changes, price alone markets will only build new generation that can be brought online for the lowest short run cost, ignoring what is the best solution for the system and a lower cost option over time.

Ohio is a net importer of electricity. The number varies a bit year over year, but Ohio imports somewhere around 15 to 20 percent of the electricity it consumes on any given day. Generally speaking, states that import electricity have higher prices than those that export electricity. Since 2005 more than 6,000 megawatts of coal fired generation have been deactivated in Ohio, while only 1200 megawatts of new generation--two gas plants--have come online. And I think it's important to note that both of those gas plants are under regulated constructs. To be fair, there are a few additional gas plants under construction, but most will not come online for several years.

So, to be clear, at least in Ohio, in the past 10 years not a single new gas plant has been added that relies on the market to survive. For Ohio and other states, the current wholesale market design is simply not working. A few years ago PJM looked at the issue of a longer term capacity price signal. And I think it's time to take another look and find a way to give the market more certainty and longer term and more accurate price signals. Regardless, it is becoming increasingly more important for states to continue their historic role of planning for their local retail customers.

Today's competitive markets have morphed into what I call "price alone markets." By "price alone markets," I mean that all resources clear on price, regardless of other attributes they bring to the system. Now, we don't believe the price

alone markets properly value the attributes of large baseload power plants. We've moved away from integrated resource planning, where state commissions or utilities would consider a variety of factors when choosing generation sources. Integrated resource planning produced a reliable electric system, and it ensured there was a party that considered factors such as fuel diversity, plant location, and onsite fuel.

Clearly, states have a role to play, and many are engaging today. Why? Because the market does not produce the right mix of generation resources for the optimal benefit of customers. Instead, the price alone market views all megawatts as the same. As a senior FERC staffer recently noted, "Current electric markets are only designed to pick the lowest cost form of power."

The sound engineering and economic practice of relying on diverse generation sources such as baseload, intermediate, and peaking units, and diverse fuels to meet customer's needs has been replaced by today's price only market. In our judgment the value of fuel diversity in competitive markets is simply being taken for granted. Remember, in large measure the markets we have today are a product of a diverse power supply portfolio based on state and utility Integrated Resource Plans of the past. The RTOs were essentially tossed the keys to fully functioning systems, and only now over time are issues with the current system being exposed.

Turning to Ohio, we have a plan called Powering Ohio's Progress. It contains a number of customer benefits, we believe. It helps keep vital baseload power plants operating. It protects customers from retail price volatility and price increases, both by retaining generation and providing a hedge against market volatility. It promotes economic development. It retains local jobs and protects tax revenues, preserving more

than a billion dollars in economic benefits. Our plan is supported by 17 parties, including groups representing residential, commercial and industrial interests. And our plan does not restrict customer shopping. There is nothing in the plan that prevents customers from continuing to access to retail choice. Today more than 70 percent of our 2.1 million Ohio customers shop with third party suppliers. And nothing in our plan changes their ability to continue to do that. In addition to keeping our plants operating, our plan provides more than 100 million dollars in assistance to low income customers and another three million dollars in economic development funds and provides for a cleaner energy future. It's designed to produce the best overall outcome for our customers.

Now, we know that nobody has a perfect crystal ball on future energy prices. However, we do believe prices will increase, and we fill that customer's need for protection from the transition happening in our industry today.

I want to share with you one example where plants shut down in Ohio and customers were on the losing end. In my real world example, customer were faced with a "heads you lose, tails you lose more" situation. In 2012 our company faced a difficult decision when several of our plants along Lake Erie required expensive environmental retrofits. The cost to upgrade the plants was around 400 million dollars, according to our most recent estimates. When PJM conducted their reliability assessment, they determined that additional transmission assets needed to be built to ensure reliable service to the area where the plants were located. The additional transmission infrastructure was not required by PJM to increase reliability; rather, it was built to simply keep the same level of reliability. The cost of that transmission fix was 1.1 billion dollars. Rather than provide incentives for a generator to spend 400 million

dollars to upgrade a plant, the market solution, the PJM price only solution, was to spend a billion dollars. Well, it was painful. We made the difficult decision to close the plants. So what did customers receive for their one billion dollar investment? They received the same level of reliability, but with lost jobs, lost tax revenue, and a negative economic impact to local communities. While energy prices have remained stable for now, our customers' transmission costs increased significantly.

And I think this highlights a real problem, and I know we'll talk about it today. And the problem is that we're solving multiple equations separately rather than looking holistically at all of the equations. The market equations said that the Lake plants should close rather than pay 400 million dollars to keep them open. At the same time, the transmission equation said to pay a billion dollars to upgrade the transmission infrastructure. I think the results would have been much different if somebody looked at both equations simultaneously, as was done back in the days of integrated resource planning.

The bottom line is that there are critical issues that need to be resolved. Our utilities have an obligation to our customers to deliver safe, reliable electricity at an affordable price. Letting key power plants, including carbon free nuclear plants, shut down with years of useful life remaining we don't believe is in our customers' best interest.

We have a plan, and it's one way of addressing the price-only market concerns we have. It's not the only way. The states are experimenting. I'm not going to go through each state and describe what they're each doing. You read about them. The bottom line is that states, regulated and restructured alike, are attempting to solve the challenges they face by correcting the shortcomings found in the price-alone energy

and capacity markets. There is a lot of experimentation going on out there.

So where does that leave us? Markets should strive to produce the lowest reasonable cost and reliable service over time. Unfortunately, the current market structure ignores key factors that have benefited customers in the past and can and must benefit customers in the future. We don't want to look back 10 years from now and realize we made a mistake by basing our choices on independent solutions rather than a holistic approach. Thank you.

### **Speaker 3.**

Good morning and thank you for inviting me to attend your session today. I'm not here on behalf of any client. I'm not involved in any of these formal proceedings that you will see mentioned here by others and myself. But I do have a pretty extensive experience representing consumers on retail market reform issues since the early days of restructuring. I've seen it all. I guess I have some advantage with my age in that respect. I sat in the room at the Maine Public Utilities Commission when the three commissioners at that time, including Dave Moscovitz, Cheryl Harrington and Peter Bradford, decided what they thought the future price of oil would be in order to set the avoided costs on the mandated QF plants that Central Maine Power was going to be ordered to enter into. So I learned a real important lesson there that a lot of people just don't seem to want to learn, which is, you can predict whatever you want, but it's not going to be a correct prediction.

So we're back to the same thing again here folks. We're talking at this particular panel about some specific proposals and some of which are new to me that I didn't even know about that Speaker 2 mentioned, but obviously the big news ones are those going on in Illinois, Ohio and New York, and basically what we have

is the owners of some uneconomic plants are not happy with what they're getting out of the wholesale market and their shareholders don't want to continue operating a facility that isn't making enough money. So that's what we're talking about, making money.

The Illinois proposal is being put forward by Exelon, who last year put forward a proposal to the Illinois legislature, and I at least give them credit for knowing where the power is in Illinois, because it isn't over at the Commission, unfortunately. So they go to the legislature and they want rate payers to pay for these low carbon emission credits to keep their nuke plants operating. The Attorney General's presentation to the legislatures estimated that that would mean about a 300 million dollar transfer from consumers to Exelon annually, and a 1.6 billion cost increase to rate payers with this proposal (through May 31, 2021). The proposal did die at the end of the session, but Exelon's executives are talking publicly about the need to bring forward this proposal again and that the higher prices and the capacity market are not really sufficient to solve the problem.

In Ohio we have a highly litigious and very complicated proceeding going on with both FirstEnergy and AEP on separate proposals to put their identified uneconomically operated coal and nuclear plants into distribution customer rate payer bills with these so called "retail rate stability riders." There is a stipulation, it is pending, negotiated many times. I don't know the answer to whether the stipulation is robust enough to obtain regulatory support, but I have seen press reports from Exelon (interestingly enough) and Dynegy, who said they can beat those prices.

In New York we have a highly politicized and gubernatorial-driven proposal from Governor Cuomo who directed the New York Public

Service Commission to develop a clean energy standard to implement New York's Clean Energy Plan, which is not law in New York, but a construct of the administration's view of the future need for energy in the state of New York. And (I'm being facetious here) when the governor figured out that closing some nuke plants in upstate New York would threaten his ability to achieve his political goal of a 40 percent reduction in greenhouse gas emissions by a certain date, because if they closed they would be replaced by, probably, gas plants that would increase--although not compared to coal--greenhouse gas emissions compared to nuclear, so he's arguing for a transition mechanism to have the rate payers of the state of New York pay for continuing operation of these facilities by developing something called a Zero Emission Credit which everybody in New York would have to assume responsibility for paying for through their generation supply. So he's proposed (and the commission has put forward a proposal in a staff white paper type of recommendation) to pay the difference between the actual operating costs, and they claim they'll look at the books and records to figure that out, and what the plants get in the market. And that's how they'll price the Zero Emission Credit.

Now, there were no cost estimates in the staff's proposal. They blithely claimed that they'll give us that later. They haven't figured out what this would cost the rate payers of the state of New York, but this construct is out for public comment. There are no evidentiary hearings planned, nothing but technical conferences and public hearings at which individuals can come and say, "Yes, please support our plant, we like the jobs."

So you clearly have a sense here that what we've got is something like the bank-related disaster—these plants are too big to fail. But what this does is turn restructuring and the justification for

it on its head. We were all told at the onset of restructuring (by academics, commissioners, and policy makers who proposed that we adopt this dramatic change in our electric system) that the benefit of this would be to shift the risk of plants not making money from rate payers to shareholders. And at the time this was being done, the utilities who agreed to do it saw that they would make sufficient profits in the early years of this system. We ask, are we naïve? Do we really think that any promise about shifting risks will not come back to haunt us? It's, "Heads I win, and tails you lose." I call this dressing up the pig.

I understand that there may be societal benefits associated with trying to keep some of these plants in operation. And I'm going to suggest to you how I think, if I were king of the world, this ought to be handled. But the point is, it's being promoted as a public relations gambit in these states to preserve low carbon or zero emission facilities. We are told that we need to keep them operating because they're base load and needed for long term reliability. We need to keep the plants operating because they're ours. They're in state. They're our local jobs. They're our communities that depend on the operation of these facilities, and we're going to really help get this deal across the goal line by handing out money to special interest consumer organizations, low income organizations. We're going to make green, renewable commitments. I mean, we're going to salt this deal with a lot of goodies to help make it palatable. And that's, in fact, what's happened in Ohio.

But the reality of all this is pretty troubling, it seems to me. I wanted to make a few comments about the obvious issues. Stranded costs. We've already paid for this stuff. Now you want us to pay for it again? Billions of dollars have been transferred to these owners and shareholders to allow them to leave our system and go out on

their own and make their bucks in the wholesale market. The benefits, they're a bit illusory from my perspective. And, again, I'm not one involved in the absolute details of evaluating these projected long term commitments and the value to rate payers in the form of prices or whatever, but I know they're wrong, because they all depend on predicting things that cannot be predicted. And the risk of them being wrong is on rate payers, not shareholders. Companies are free to close these plants anytime. They can sign a deal and close them a week later. How many of us are familiar with stories in our states where tax benefits and credits were given to competitive businesses to lure them to our state, and two years later they've declared bankruptcy and left? I mean, it's the same thing here folks. There's no guarantee. The bottom line is that we're shifting risks back to rate payers. That's the bottom line. Is that fair? I don't think so, but I understand there are arguments either side.

The wholesale market implications for this are truly astounding. Is the wholesale market only going to be allowed to operate when it benefits certain large generating clients? These proposals all seem to assume that the market will not be allowed to work, and they want to change the market. Is this a ploy to get a change in the way capacity is handled in the wholesale market? I don't know, but this suggests to me a significant structural issue that goes way beyond whether the deal in Ohio is a good deal for rate payers or not.

And there are enormous implications for retail regulatory authority here. These long term deals are not accompanied with any traditional regulatory oversight about protecting consumers from imprudent or improper costs, such as would exist in a vertically integrated state. Plus, the notion that we preserved retail choice is not a fair description of what is going on here. Yeah you may have theoretically allowed people to

choose an alternative supplier, but you've imposed the cost of these generating plants on a non-bypassable rider, as part of the distribution part of the bill. Now, if that isn't skewing the system, I don't know what is.

The politics of these proposals are taking over whatever regulatory niceties and analysis and economic input we may be arguing about here. I think these issues need to be viewed as whether or not society and tax payers ought to be paying for the privilege of having plants located in their state in order to preserve certain economic and social benefits. If that's what we're dealing with here, that's who ought to be ponying up the contribution to keep them in operation, not rate payers--not if you want to continue the notion of a restructured market.

The other option is, let's get rid of the notion of restructured markets and acknowledge what has been happening for years in the restructuring states. Do you think that the states have adopted these mandatory efficiency expenditures and consumption reduction goals, renewable energy portfolios, distributed generation, and solar mandates and clean energy or carbo emissions standards to affect the distribution systems of our utilities that they regulate? No, no, no, no. We're paying, through non-bypassable surcharge in the distribution part of the bill, for attributes and programs that are clearly designed to impact the over 50 percent of the bill which is generation supply.

So if we're going to do these deals in any of these states, we ought to recognize what's happening here and call the wholesale market a failure and get back to putting together a politically acknowledged state regulated utility system that allows customers the faint hope of prudent review of costs for the benefit of rate payers.

One more item. I was shocked at the lack of any mention of distributed generation in the prediction about what is available to meet the generation needs of consumers in any of the charts we saw by the two entities that own generation facilities. Isn't the whole point of the revolution of the future that we're going to distribute generation throughout the distribution system and not rely on these big power plants anymore? Isn't that the green agenda and vision? So there are sources of energy supply that are supposedly being developed around the country that are supposedly going to allow us to operate a more dynamic distributed system without relying on these big base load plants. Isn't that issue also integrated into these discussions that we're going to have today? Thank you very much.

**Speaker 4.**

Thanks for the opportunity to address what is a very timely topic, as everyone knows. As you know, I'm absolutely proud to represent utilities that supply 10,000 fuel diverse megawatts, largely in the RTOs of those who did what policy makers in Washington, Columbus, Albany, Springfield, and other places asked them to do, which was come to states and invest in existing and new resources on a competitive basis. They are entirely dependent, of course, on these market revenues to succeed in doing so. I actually agree with a little bit of what everyone said who spoke before me. Obviously, Speaker 1 has been the vanguard in saying that you have to pick one model over the other and improve the price formation. I agree with Speaker 2 that we need a holistic approach, but obviously disagree that what's being put forward is such a holistic approach. But I think Speaker 3 really hit the nail on the head in terms of disabusing anybody of the notion that retail choice could possibly exist with a non-bypassable charge.

The theme I bring to this is that just at the very time we're dealing with the Clean Power Plan and integrating distributed resources, when it seems like we should find attractive the risk shifting, the innovation, and the other benefits of competition, what's happening in Ohio, and what could happen in other states, actually moves us backwards and prevents those very benefits from coming to fruition. In some sense, if we had to look backwards and say what could we have done differently or should we have done differently in restructuring, we come back to this notion that we could have either cost of service or a market--either can work. But we allow sort of the these different hybrid intrusions into the marketplace to the point now where if it's allowed to continue (and it's not just Ohio, although it's the most recent example) we're going to have this situation where those of us who are supposed to invest face price signals that are so muted that they distort reality. So this does become sort of a spiral to the bottom.

And this is the 58th or 59th year that I'm hoping the Cubs win the World Series. So I'm optimistic particularly going in this year. Go Cubs. And maybe because it's baseball season and because I'm batting cleanup, but I thought last night, it's one thing for the American League to have the designated hitter rule, it's another thing for the National League not to have a designated hitter rule, but imagine if you had a situation where in the National League, the home team gets the designated hitter rule, but the away team does not. Or, similarly, the home team gets the bat until it gets six outs in an inning and the away team has to stick with three. And that's precisely what's happening with what's being proposed in Ohio and what we've seen in other instances. We've really been building up to this, I think, to some extent for the past several years, as everyone knows. First, it was Connecticut, and then, of course, we have the famous Maryland and New Jersey examples,

where we had contracts for differences with outside non market revenue streams, and at least in those cases, the states were openly seeking price suppression, as two District Courts and two Courts of Appeals found. At least in those instances the process was a competitive procurement process and they were non-utility affiliates. And, thankfully, what happened there was self-correcting in that the PPAs that were awarded (although never allowed to go into effect because of the court action) were two, three and four times the market price for capacity. And through the court actions the subsidized plants actually were built, most of them, without the subsidies at lower costs. New plants came in at market, including in the areas of the plants that were to be subsidized. And, as I mentioned, the Federal Court struck them down, and nobody else really followed that model. Now what we have is even more megawatts.

Remember, it was a 1,000 or 2,000 megawatts issue in Maryland and New Jersey. Now with Ohio, I think if you add up what's AEP is seeking and what FirstEnergy's seeking, and now what Dayton Power and Light is seeking, we're talking about 8,000 megawatts, and instead of being an economic entry we're now talking about an economic non exit or even claims of exit that really aren't quite valid. It's not true in the FirstEnergy case, but something to keep in mind in terms of how absurd this is getting is that most, if not all, of the AEP plants are co-owned with Dynegy. So you're going to have a situation where the plants can't close without the permission of the co-owner. So you're going to have plants with the same fuel, the same employees, the same site, the same everything. Some receiving (and you have to keep this in mind, we're talking about prices under the PPAs that Wall Street has estimated to be \$75.00 per megawatt hour at a time when the market price is \$25 to \$35, and when capacity

prices in PJM are sub \$200, sub \$150 a megawatt day. Some of the AEP capacity prices are \$500.00.

So this would all be bad enough on its own, but we also, as we're discussing this today, have to take into account the broader context. And that is the broader issue that more and more resources are being able to bid in at zero. So if you have the bid based economic dispatch system that operates on marginal costs, you're going to have resources that have inherently zero marginal costs, like renewables. You're going to have other resources that may also have inherently zero to low marginal costs that are being subsidized through the investment tax credit, the production tax credit, and now we're going to have, on top of that, resources that don't have actual zero marginal costs, but have these out of market revenue streams and then can bid zero.

The economics of this are pretty straight forward. This is what came out when the Maryland and New Jersey contracts were being debated. And I would argue that the same is true with what we're seeing now, where instead of trying to inset new generation we're trying to provide non market revenue streams to only a select subset of plants operating in the same market, competing against each other.

To its credit, PJM has been very outspoken about this, as has the Market Monitor. I think everybody knows how this works. If a subset of generators can bid at zero, that then really shifts the supply curve. This curve is very sensitive, and so you actually end up with a very large impact of price suppression out of everybody else in the marketplace, not only in the state that engages in the activity, but throughout the region, from a relatively small amount of generation that's additional supply that's injected into the system. This confiscates value

from the existing generators. And those existing generators are at risk. And then, of course, who would come in new into this kind of a system?

So we end up with this one set of out of market actions that begets more and more. And, as I said, this is not theoretical. In Maryland, just 1800 megawatts suppressed the capacity market price by 37 percent. And if both Maryland and New Jersey had done what they proposed to do, the prices would have collapsed by 45 percent. So Speaker 2 is absolutely right. The price hasn't cleared anywhere close to the cost of new entry, but the answer should not be to make the price collapse even more and be farther and farther away from the price of new entry.

So with Ohio we don't have 8,000 megawatts, as I said earlier. It really shouldn't matter legally or economically whether there's an explicit bid and clear requirement as there was in Maryland and New Jersey. The effect still is to have one set of power plants, have a contract for differences, and get a different price than what everybody else would get in the market. Some say, "Fix the Minimum Offer Price Rule," as the courts have said. That is proof enough that there's an encroachment taking place from the state into the federally regulated wholesale market from a legal standpoint, and we know how controversial the MOPR has been. But keep in mind that if that's what's pursued (and that's one answer to this problem, just make sure everybody bids real costs) then the consumers and the states that engage in these things end up paying twice.

So they can actually have a situation where, if generators are forced to bid the actual costs (which they claim they can't recover in the market now, so they're admitting they're out of market, otherwise they wouldn't be seeking this), they may not clear. If they don't clear, then the customers will not only pay the capacity charges through PJM, they'll pay the contracts

for differences costs in the contracts that we're talking about.

There's also a capacity performance angle to this. Giving a subset of generators in one state, preferential PPAs for an eight-year term (or whatever term) that is not available to everyone else undermines capacity performance, because the risk of nonperformance no longer falls on the generator, to incent the generator to do the things the generator is supposed to do, and the things our members are already doing to ensure capacity performance. Instead, like everything else, the risk falls down to the customer.

So the question becomes, what to do about this. The first thing, of course, is to just say no. These PPAs in Ohio, as you know, are very controversial. It's a minority of parties to both cases that agreed to the settlements. The house staff was vehemently opposed to them as originally proposed. This is, again, extremely controversial. The airwaves have been saturated by both sides with ads. Over 100,000 communications have been sent to the governor's office, the PUCO, and the legislature opposing them. It's the first time in my 11 years at EPSA that we have been allied with the Sierra Club, the AARP, Ohio Manufacturers', hospitals, and the Ohio Office of Consumers Council.

The federal courts obviously will play a role here. We all know the case was heard a few weeks ago involving Maryland and New Jersey. It's undoubtedly the case that there will be federal court action here again as well, but think about what happened with the Maryland and New Jersey cases. Maryland and New Jersey started in 2010, 2011, and here we are in 2016 still awaiting for a decision. So things are moving in the market so rapidly that waiting for the courts to act...while I think eventually they'll do the right thing, it doesn't avoid the

damage. There's a potential for state court action, of course, and then there's the FERC. And as our moderator said in the opening, and I think it's very true, ultimately, this is a question for federal regulators. These are wholesale contracts. These are not state-only contracts. These are between regulated entities at the state level who are merely passing through the costs. The real question is the contracts themselves that were negotiated internally to each company, between their first jurisdictional wholesale provider with market based rate authority and the local utility.

So this is a two step process that you'll see moving forward. There are waivers that were given, back when retail choice was meaningful to each of the utilities, that said they did not have to follow the otherwise applicable affiliate abuse rules. If this isn't affiliate abuse, it's hard to say what is. So the first step is the complaints that we and others have filed, including the Office of Consumers Counsel supporting us, the Pennsylvania Commission, PJM, the market monitor, and the long list of businesses and consumer groups... I can't think of anything else that's brought such a diverse group together. We'll see how that plays out. If the complaints are granted, the waivers go away, then we'll actually be able to see the contracts, and FERC will have to rule on the merits, as we believe they should.

But most importantly, to come back to the beginning of what Speaker 1 said, we started a project three years ago now. Speaker 1 and other leaders came to us and the other associations, and we went to the commission on price formation, both day ahead and real time. So we went forward three years ago, and while there's been some progress, not nearly enough has happened quickly enough, and so if something doesn't happen pretty soon on that agenda, more broadly and boldly than has happened to date,

these are the kinds of things we're going to get, because people are going to look at their assets. They're going to look at their duty to shareholders, and they're going to grasp for whatever straws they can find.

Secondly, we've already talked about capacity performance, but really we have to do more on price formation, and we really need to get ahead of the curve because I think it's starting to happen, through forums like this. There's the *Quadrennial Energy Review* at the Department of Energy, and that's looking at capacity markets and essential reliability services for new products, so that we do value the ramping and the voltage support and the frequency response and the other attributes of nuclear, coal, and gas plants. We have to start looking at alternatives to LMP, or alternative forms of LMP, and possibly even look at two tier pricing. If we're going to have so many megawatts that have zero to no marginal costs only because that's in fact the case, or because their masking not having zero marginal costs through these out of market subsidies, so that we need to come up with a new subsidy, or a new pricing system. Because the 210,000 megawatts that we represent are still going to be needed for reliability, and it's not sustainable. It's not even feasible, or, we believe, legally justifiable to say they have to compete in a world where some people get the designated hitter rule, or six outs, and the rest of us play by different rules. It's not sustainable. And so I look forward to the discussion.

*Moderator:* A clarifying question to Speaker 1. When Entergy announced the retirement of Vermont Yankee, there was a general statement about market flaws. ISO New England market flaws either contributed to or caused the retirement. I thought it was more of a cause sense, but it might have been a contributory sense. But in your remark you said that there's not really a silver bullet, so I was wondering,

you know, are there three silver bullets? If you were vested with all federal and state power, and with a stroke of a pen you could make three or four changes that would save uneconomic nuclear plants, what would those things be, and what's the most important, second most important...?

*Speaker 1:* Well, for nuclear plants, the first issue is how you value the zero carbon emissions. So you put a price on carbon, OK. So that's probably number one, especially in light of what your long term objectives are. The second thing would have to do with the pricing structure for capacity and energy, and you know, that was, and we've seen some improvement in ISO New England's capacity pricing structure. We think there's significant opportunity to improve the energy price structure by minimizing or eliminating uplift. And so those would really be the top two things that would help tremendously. And obviously a key driver is low natural gas, where we know there's nothing we can do about that. And, lastly, I will say, it's the out of market issue. It's the subsidization of things like putting in natural gas pipelines by the retail rate payers, which we simply don't agree with--those types of actions that are done at the local level to, you know, pick winners and losers, is also a key consideration. So it's the combination of those three.

*Moderator:* Great. Thanks. Helpful. And, Speaker 2, just one question. You talked about a multi-year product, and then you also talked about valuing fuel diversity. And with respect to valuing fuel diversity, there was some discussion about tranches of capacity products. So there'd be a nuclear product, and there'd be other products, but, you know, one concern is that that vastly complicates already pretty complicated markets. Another is that it really opens the door to market power. If some of these products

actually have very few possible providers, and if you, for example, ask for a seven year nuclear capacity product, where actually very few people could provide that product, you could really end up with a pretty bad outcome from a consumer point of view. So, with tranches, and a multiyear product, are you talking about three years, five years, seven years?

*Response:* It's more than three years. And I'm just not sure I know the answer. I know there's an HIS study out there about diversity and the value it brings to customers, and it's not a small number. Its 93 billion dollars. Now, I haven't read the whole study, but from their perspective diversity saves customers money. How we retain that diversity and how we flow it through to customers is something we all need to think about and make sure it happens, if we can do it in a way that makes sense for all the parties. You know, we talk about competitive markets and bidding and all these things. 80 percent of the folks who bid in the PJM capacity market bid zero. Not just nuclear. There's simply not a market that I'm aware of, I'm a little hesitant to say this because Bill Hogan's right there, where that happens.

### **General discussion.**

*Question 1:* Thanks. My question is about missing money, because if I look at the markets (and PJM is the one I'm more familiar with) through at least 2020 you've got more resources than PJM needs to meet its reserve margin, and new resources bid in every year and clear. So even if the clearing price is less than net CONE, whatever you can say about missing money, you can say that new resources are coming into the market. So I wondered if you could get all the panelists to comment a little bit about what missing money really means, and to what extent is that kind of a red herring in the analysis here.

*Respondent 1:* While auctions may result in enough megawatts showing up to meet customer's needs, it's a snapshot in time. Its one year. And the question for policy makers, for utility companies, for commissioners and others, all of us, is twofold. Is it the right mix of megawatts today, tomorrow and in the future, and how long will it last? I think that's my response to your question. I hope I got your question right.

*Respondent 2:* Well there's so many missing money experts here that I hesitate...I think it's funny, all in all. I mean, we talked about this before. You've got something in electricity that we don't have anywhere else, which is a requirement for surplus. You've got the interaction between energy and capacity markets. And I think that while things may be working OK now, you just have to look down the road to see where the forward curves are, at the hard business decisions that folks are making in order to see that the need is still there. Everybody's paying for capacity, so it's a question of whether you do it in a transparent, competitive manner or not. So you really need both. I think that's been proven up by all the research. I don't want to belabor the point. We can talk more about it if folks want to.

*Question 2:* I'm grateful for the previous question, because I think the framing is right: is this a reflection of things that are supposed to be happening in a market and that's just the problem, or is it a problem of market failure? And I think the answer is, we don't know. And that's because we have both things going on at the same time. And so we certainly have very serious problems of market design that never get the attention that I think they need, and I was trying hard over the break to think of another way to say, "Get the prices right," and I have a list of the things that I think would need to be done, but there're all doable.

I think the problem has always been that we just dismiss too easily out of hand the consequences of not doing that and not getting the prices right, and then we get into the messes that we're talking about here. And I am quite worried about this, as you know. Speaker 3's characterization of this struck me as correct, except for one thing about this. I recall there was the "dash for gas" a while back. And then we built a lot of new natural gas power plants, and then the price of gas went up, and these new gas power plants weren't so economic, and a lot of shareholders lost a lot of money. So we've been through it once where, in fact, we didn't shift that risk back onto the customer. So as to whether we're never going to do it this time, I don't know. But this is not the first event in that sequence, and that's an important precedent.

That gets me to my question, however. Because one of the issues that keeps coming up in all of this kind of stuff is clean energy, CO2, carbon. What is the appropriate policy? One way to look at this is we're having a national public debate about how we want to deal with this problem, the carbon problem, and we haven't resolved that issue. And as a matter of policy, at the national level, where a price on carbon is highly contested, it hasn't been fully resolved. And a lot of the things that are happening here--arguments about how we should support this plant or support that plant--are in a way to try to avoid that debate, or a lot of the arguments that come up for things like renewable portfolio standards talk about, "Well, we need to do a little bit to get started." Now we're getting past the getting started phase. Now we're getting into just a massive subsidization of these programs, when we haven't resolved the fundamental debate. And so I personally am in favor of a very significant carbon tax and would adopt it tomorrow if I had the choice. As a matter of public policy I can make the case that this would

be inappropriate for regulators to do without having the explicit legislative authority in order to deal with that. And until we get that issue resolved, we're going to have to deal with this dilemma. So, how do we think about that issue, where there is a fundamental disagreement in the country, and what is the role of regulators and regulation in that context, when we haven't resolved that disagreement?

*Respondent 1:* I'll take a shot at that. I mean, the fact is, you're exactly right. So, we have no clear policy yet. State and local regulators have some idea of where they want to be, but it's not clear how they get there. For example, take the Clean Power Plan objectives. You know, given that we cannot reach consensus on a national level, I think this is going to end up going to the states to decide, and, you know, there's broad plans for 50 percent renewables, 30 percent renewables...which I think is all fine. What's missing, as you suggest, though, is there's no path to how you actually get to that end state, because there are no long term objectives. And so the way I see it is, you know, if we lose--if some of the cases that Speaker 4 talked about, whether the Maryland case or the New Jersey case...we're going to be in a situation where you're going to see merchant generators, not just nuclear, that are going to be very, very challenged in this price environment. And I hate to say this, because I'm a big fan of markets, but at some point you may have to move more to a regulated market structure to be able to bridge that gap. I just don't see how we're going to deal with this nationally, given the fact that we can't even come up with an approach on carbon. And each state will then have its own individual objectives that it wants to meet, and doing one off deals to try to save specific plants is just not sustainable.

So again you need to really think about whether this moves you into more of a regulated market.

An example of a market that kind of uses both regulation and market benefits is MISO. So, we have our Southern utilities in MISO. So in that market we're held accountable to the PUCs in that area. But at the same time we're able to take advantage of the benefit of broader economic dispatch. So as you think about what the range of options is, that type of situation is probably much more palatable from an investor's standpoint, as opposed to just continuing to try to work in these other markets where they pick winners and losers, one off deals, RPSes, et cetera, and, you know, pretty soon you're going to see more and more generation fall off the table, especially at these low natural gas prices.

*Respondent 2:* You know, there's a precedent for how to solve this problem, and I hate to point to it because it's a behemoth that has dysfunctions in itself, but that's California. I mean, they went through experiencing a real crisis and completely eliminated the notion that they were going to rely on some hypothetical wholesale market price to determine what retail customers would be charged. And they immediately moved into a more totally regulated system, and they have a wholesale market, and the utilities can buy and sell in that market, but when they impose their carbon rules and their solar mandates and their distributed generation and their renewables and their green stuff, it's all done in the context of, "We're regulating our system, distribution and generation." And at least it's not the hypocrisy of what's going on in some of these restructuring states where they claim they have a restructured market and in fact they spend all their time imposing mandates on regulated rate payers for their generation vision about low carbon emissions. So, you know, I'll fight them on the base rate case system anytime, versus this loading subsidies onto the non-bypassable distribution part of the bill, any day.

*Respondent 3:* Obviously, we agree that the price needs to be right, including on carbon. I don't think we can answer your question, which is an excellent one, at least until we get past the November election and we know who's in the White House and who's going to appoint the next FERC commissioners and EPA and, more importantly, the Supreme Court. I know this makes folks at FERC shudder, and you and I have been on other forums where this issue's come up and I've raised it, but after the *FERC v. EPSA* decision on demand response, there are some in the various legal circles that have looked at that and the webinars that have taken place saying, you know, it's such an expansive interpretation of FERC authority, more than they probably ever thought they had, that perhaps even FERC could tackle the carbon issue. There are law review articles, from even before the *EPSA* case, I think, going back about two years ago, from the University of (I think) Cal-Berkeley, and certainly New York University Law School. So there's an interesting question of, could you get at this, if not a direct carbon fee? I know Commissioner Anderson's happy that Texas won't be subject to the FERC jurisdiction in that regard. You could have a shadow price on carbon, but there needs to be some rationalization along the lines you suggest. I just don't see it happening until we at least get past the November election, and then folks will have to give more thought as to whether FERC is actually a route worth pursuing. That's one suggestion that's starting to get some greater discussion.

*Respondent 4:* I'd love to think we could get some kind of price on carbon and that would be the building block for other changes, but the unfortunate reality is just that there is no consensus on this kind of policy. The last major environmental law passed at the federal level was the Clean Air Act of 1990. And since then any kind of bipartisan consensus on

environmental policy is completely gone. Energy policy is frequently bipartisan. I think it's still possible. But it took a Republican president and a Democratic Congress to pass the Clean Air Act amendments, and that consensus is gone, and I frankly have a hard time seeing how it can be reassembled. The only scenario I can think of is, you know, if somehow the Clean Power Plan is affirmed and a new administration decides what we want to do, and they say, "We want to address carbon. We want to do it in a smarter way that's more economically efficient," and they invest political capital in that goal, in some kind of bipartisan way, so they have a little bit of, they have sufficient credibility. And if they have a lot more tactical skill than the current administration dealing with Congress. But it would seem to have to start with the Clean Power plan being reaffirmed and then negotiating from that point towards some kind of federal carbon price. I mean, that's a scenario. There are a lot of ifs in there, but frankly that's the only way I see that happening at the federal level.

*Respondent 5:* It's a good question, and I won't spend too much time on it, because I agree with most of the comments from the panel. The unfortunate thing is that nuclear power plants, even without the carbon price are being undervalued.

But I want to respond to something that I think is woven into a lot of the discussion already including related to this question. The states have a right and responsibility to set retail prices and to develop retail programs. And I say that because, while we may not have consensus at the federal level on this and other issues, certain states will act, potentially, on carbon and other environmental issues and on a whole host of other things that I think could help. Now, as a national program, would it be better? Would a regional program be better than state by state?

Maybe. Probably. But the states can and will and are doing some things in this space.

*Question 3:* Yes. Speaker 2, you mentioned fuel diversity as an objective, and while notionally I think that's a good thing, the practical thing is there's really only two or three fuel choices anymore. There's the renewable intermittent. And there's gas. Really, in terms of new build, those are the two choices.

Even in Texas it'd be impossible to get a permit for a coal plant. You'd be in litigation for, you know, a decade. And so, really, isn't that a, isn't that a red herring now? Isn't it really an excuse to keep existing plants that have high heat rates or high operating costs in the market, when really economics would dictate that they ought to be closed and replaced by cheaper gas? And a little different example is what's happened in Mississippi with the Kemper Plant. I'm all in favor of R&D, but, you know, from an economic standpoint would you have ever spent that kind of money to build a coal plant when you could have spent, I don't know, a quarter, maybe less, maybe 20 percent of the price, and gotten twice the megawatts of gas? It would be cleaner and lower cost.

*Respondent 1:* That's a good question, and I don't disagree with you about where folks are building new generation and where they're going to put their money. That I don't think is the question--or it's the short term question. If fuel diversity saves money for customers...we talked about the boom and the bust cycle, and some of us with this kind of grey hair remember the "dash to gas." We relied too much on one fuel. It's going to happen again. We should learn from that, and so, while I think you're spot on as to what will be built, again, regulators, legislators, folks at the state level, folks at FERC, PJM, we need to look past the next year, and past the next two years. I don't know how to

do it that really works for all of us, but I know that if we don't, customers are going to be in trouble, because they're going to be paying more. I get that prices are low now. I get it. I think it's great for customers. But this will turn, and when it turns you're going to get those customer calls, at least I am. Those of us with customers at the other end of the line.

**Question 4:** Good morning everybody. This is an interesting panel. I've got some observations and then a question. I think it's very interesting. We talk about fuel diversity and everybody's attributes--everybody's special. I feel like I'm living in a Garrison Keillor skit. We're like Wobegon and everybody's good looking and above average here.

But just one observation. Energy, electric energy, is homogenous. It doesn't matter where it comes from, whether it's a nuclear unit, a coal unit, a gas unit, once the electricity is generated, it's homogenous. And I see a lot of people shaking their heads no. Do you care when you turn on your light where it's coming from? It's electric energy. That's what the markets are for, and really all resource adequacy is an option on that homogenous product. And so in that sense, we're trying to minimize the cost of procuring energy. Energy is the product here. It's not anything else. If we want to develop products for carbon dioxide we should do that in a separate policy. So, effectively, it shouldn't matter what the age is, what the size is, what the fuel type is, what the technology type is. As I was once quoted in the trade presses saying, I don't care if you put a hamster on a wheel and feed it lettuce. If it generates electricity, it's electric energy. That's all we're really talking about here.

And so, with that being said, if we really are concerned about diversity, PJM, at least, is becoming more diverse. I go back to 2007, before we even had these discussions. Coal was

55 percent of total energy, nuclear about 35 percent, gas seven percent. I didn't hear anybody screaming about fuel diversity back then. Now in 2015, coal was about 36 percent, nuclear about 35 percent, gas about 25 percent. Sounds more diverse to me, doesn't it? So I don't understand this fuel diversity argument at all. We're actually becoming more diverse, not less diverse, here.

And then the other thing about capacity markets is, yeah, it's only 20 percent of total cost, yet we seem to be fighting the Holy Wars over it. So, with that being said, with all the talk about subsidies and everything else, given those observations, how would you, each of the panelist respond to the following? I'm a state commissioner in a state that's choosing not to subsidize electricity. And if somebody subsidizes it in another state, that means the price of that energy capacity goes down for my rate payers. That's a beautiful thing. How do you sell that to your own customers, who are saying, "This is the greatest thing since sliced bread," because they're helping pay for energy for other customers across state lines who are not doing the same thing? How would you respond to your customers if they confronted you with that?

We're not talking about Maryland and New Jersey. We're talking about states that are not like Maryland or New Jersey or what's going on in Ohio in that proceeding that are just saying, "No, we're just going to let things go. We're just going to let it ride. We're going to let the market work and do its thing. We're not going to actually pay up front for all this stuff," OK? How do you sell that, because I've actually had commissioners who are no longer sitting on commissions across the states say, "I'm perfectly happy if state X does this, because it's going to help lower my energy capacity prices."

*Respondent 1:* Can I ask a question back to you? Why is the Pennsylvania PUC opposing FirstEnergy's proposal before FERC? If your theory is correct, Pennsylvania would benefit from the higher prices paid in Ohio.

*Questioner:* I cannot speak for the Pennsylvania commission.

*Respondent 1:* They made a public statement about it, but your hypothetical isn't comporting with it.

*Respondent 2:* I'm not buying into the premise that I don't care where electricity comes from. Maybe we shouldn't, but states have the right to care where electricity comes from. And in the example I used in my presentation, you know there are costs beyond generation. Transmission costs in my Ohio example went up a lot, a lot more than total costs would have gone up if we invested the 400 million dollars in the generation plants. So I think it matters where it comes from. I'm kind of with maybe Respondent 1 on the state example. I'm just not maybe getting the question.

*Respondent 3:* I actually kind of like it. As you might imagine, I think the questioner was too kind to say it, but Respondent 1 identified it, I think Pennsylvania's being very consistent. Pennsylvania was involved in the Maryland and New Jersey cases. Now they're involved, at least at the FERC, in terms of the federal aspect of what's going on in Ohio. And I think your example is a good one. I mean, if these states take these actions, these are voluntary decisions. There are utilities that wanted to be in PJM when it was favorable to them to be in PJM. States voluntarily restructured their markets. They're joined together in a multistate region, obviously, in your case the largest, with what, 13 states and 65, 70 million people, so what happens in any one of them affects everybody

else in the system. So if you have a state like Pennsylvania that wants to stay with real retail choice, wants to have the benefits of competition, doesn't want to entertain what's happening in the states around them, I think it's perfectly consistent for them to say, as they've done now in several different iterations, that this is not something that's consistent with what they want to see, and so the damage can't be contained in the states engaging in the action.

And obviously states have retail jurisdiction, but the FERC has the wholesale jurisdiction, and that was reaffirmed very clearly what I guess we'll still call the EPSA case, and it was helpful for us now in this regard. And states are not free to do just whatever they want. We still have a commerce clause in the constitution. As I said, we've had eight federal judges hear this attempt. The Supreme Court may narrow the basis on affirming the decision, but I think it would be quite a surprise if they were to overturn it. I mean, the idea that the effects are isolated to a state, and therefore the state can do what it wants just kind of goes against the grain of the interstate system of commerce generally, and certainly with electricity, which is why, ultimately, FERC and the courts will have to rule on this.

*Respondent 4:* I would just respond that there's no one right retail choice program out there. All states developed over time their different retail choice programs. And Pennsylvania's is different than Ohio, different than New Jersey. They're all different. There's no right or wrong retail choice program. Ohio's retail choice program, through Senate Bill 3 and Senate Bill 221, allows for the kinds of things, as does federal law, that the Commission has now before it, with respect to these purchased power agreements. The question for the commission in Ohio is, is this retail program in the best interest of Ohio customers?

*Respondent 5:* Well now, let's be a little careful here. Let's make this interesting. This is important. As Respondent 1 said, you're right. Everybody has a different retail choice program, and the FERC's role is not to say what's a good or bad retail choice program. The question before FERC is more narrow but equally important, and that is, where the representations retail choice made at the time the waivers were granted intended to insulate the contracts from any review by anybody? So in Columbus the position of the utilities is, "You, Ohio commission, can't look at the substance of the contracts." They can only fund them. They're wholesale contracts. They're FERC, and so now the representation to FERC is, "These are state matters, and you, FERC, don't get to look at them." And the relevance to the retail choice is, the reason why FERC granted the waivers is the obvious. If you had retail choice so that somebody could not buy from your facility, and instead buy from a competitive supplier, avoid the cost of these plants, then that retail choice acted as a discipline on the affiliate abuse that's at issue. But as Respondent 1 said, quite correctly, if everybody pays for this in the retail choice program, regardless of whether or not they take service from those plants, this incentive or disciplining function is no longer present.

So to be clear, first start looking at saying, Ohio did it right and Pennsylvania did it wrong, or Pennsylvania is better than Ohio. It's very specific to whether or not the fact that it's a non-bypassable charge means the waiver should no longer apply.

*Respondent 4:* I get that it's helpful to your side's argument if there is a regulatory gap. And while we're not going to try the case here today, I don't think, but --

But I would just suggest that there's no regulatory gap. The Ohio Commission has the authority to review this retail rate program. They're doing it now, and if and when they approve it, they'll have the continued ability to review it, as they do with all other retail rate programs. And we talk a lot about non-bypassable charges. Non-bypassable charges are staple of state rate regulation. There's all kinds of non-bypassable charges. There's all kinds of things for low income assistance programs, for energy efficiency. There's nothing inherently wrong with non-bypassable charges.

*Respondent 1:* Yes there are. [LAUGHTER]

*Respondent 4:* I don't think so.

*Respondent 1:* Let me just say that there is a vast difference between the retail restructuring policies in most of the restructuring states versus what is going on in Ohio and the proposal in Illinois and New York. It is correct that the states, including Pennsylvania, have the right to develop a portfolio of generation supply products and contracts for default service in Pennsylvania and in other states. That is a far cry from entering into or approving a deal in which distribution rate payers are required to pay a particular type of generation supply product as a result of these contracts, so that's a huge difference. My understanding of the New Jersey and Maryland litigation has to do with the nature of the contract, and not the concept of having a state involved in procuring generation supply for its customers. So I just want to say that is a big policy difference. If you're trying to make sure default service is stable and fixed price and reflective of a portfolio and mix of products and services, the states have full authority to do that. But that is different than what is being proposed and debated here in this morning's panel.

**Question 5:** Continuing on the theme of the non-bypassable charges, I'm wondering about your views on the question of whether the negative externalities of the generation that's not being supported by the non-bypassable charges are large enough. I mean, take environmental negative externalities--might the non-bypassable charges actually be beneficial in the sense that they are approximately correcting a market failure? Not perfect, granted, but might they be actually beneficial?

*Respondent 1:* No.

*Respondent 2:* No. [LAUGHTER]

*Respondent 3:* Yes. [LAUGHTER]

*Respondent 1:* It boils down to what your objectives are, and then, how are you going to achieve those objectives? And, you know, that's the missing piece in these markets. We don't have a long term objectives in terms of where we want to head, or a path of how we're going to get there. Ultimately what's happening is that because the markets aren't working we're forced to take other actions to meet customer needs, meet shareholder needs, et cetera. So I guess the missing piece for me is, you could talk about anything that you add on a bill, or you can talk about subsidies, you can talk about all kinds of things, but we're missing what the long term objectives are for reliability, cost, and environmental sustainability. And so we can get down to the mechanisms, or we can look at a policy that tries to address those. We have not seen that come out on the federal level. Where it's going to end up is at the state level. The states are taking their own actions because we're not getting what we need to meet those objectives in the markets.

*Respondent 4:* I think that's right. And to Speaker 3, I'm not so sure how you can be so

absolute on non-bypassable charges. We have, in Ohio and some other states, a charge that all customers pay, a non-bypassable charge to help low income customers pay their utility bills. Now, from our perspective that's a pretty good thing.

*Respondent 5:* No, you don't. The costs of the low income program are included in distribution rates along with many other costs and expenses by the utility, and as a result of FirstEnergy's proposals there's this uncollectible surcharge that's been negotiated in Ohio which does include some of the uncollectable costs with the low income program. But that's a surcharge that has nothing to do with that notion of non-bypassable charge.

*Respondent 2:* Just briefly, I uncharacteristically gave a one-word answer, but I think this question, juxtaposed against Question 1, at the risk of saying the obvious, shows the difference. Obviously, the non-bypassable charge, if it were really pricing the externalities... first of all, it's going to both nuclear and coal. So it's not based on the carbon emissions output of the plants. Even if it were, the whole point of pricing the externalities is then to make sure that there's head to head competition. So needless to say, that would affect the bidding stack and the supply stack, and that's not going to happen with the non-bypassable charge. If we put a price on carbon based on the emissions output, nuclear plants wouldn't pay any. Other zero emissions electricity sources wouldn't, but gas would pay say half of it, and coal would pay whatever the right number is. That's going to affect the bid stack, obviously, and the supply stack, so the non-bypassable charge is really not an externality pricing mechanism, but it's not a substitute, and even if it were, it wouldn't do what a real price on carbon would do, which was obviously reward properly less carbon intensive resources. So it's really not a substitute.

*Question 6:* I guess, because I heard New Jersey called out a few times, I might as well say something. I have a question for each of you about the long term macro issues in and around deregulated markets. My question is, where are we in the life cycle of restructuring? Are we on the road back to regulation, or are we in the midst of the maturation of these markets? What do you say to us as policy makers and us as regulators about where the industry wants to be? There sort of seems to be a lack of clear policy. What should be the policy? What do you think we should be doing in this life cycle of the deregulated markets?

*Respondent 1:* There are a lot of people interested in the answer to that question who are not at this table. Fair enough. And I have no intent to try to tell you an answer to that question from all consumers' point of view. But I will say that it's growing more obvious to me personally that this bit of the hypocrisy about pretending that we have a restructured or deregulated market... I mean, that was the point of restructuring. The retail competition, alternative supplier thing was, in my opinion, a total failure. But the whole notion of restructuring was really adopted to try to have a different way of pricing the generation part of the bill. So I think the answer to the question needs to focus on that. And the problem is, we've never really done that. New Jersey and every other state has adopted and continues to adopt mandates for renewables, efficiency, carbon, low carbon approaches...All of those things are not capable of being regulated in a restructuring state by impacting the generation part of the bill, because it's now subject to federal regulation, and because of these bureaucracies at PJM and MISO and whatever. So governors and politicians have created this hybrid situation without really confronting the implications, and I think we need to go one way

or the other, and if in fact it is correct that people are not going to let these coal and nuclear plants shut down for whatever political or economic or social reason that is put forth, then we ought to just confront the reality of what we're doing here and go back to full regulation at the retail level of the generation supply. And if your utilities in New Jersey or elsewhere don't own much anymore because they're now given away, because we paid for them to be given away, then you're going have to rely on wholesale market mechanisms to buy generation supply and go back to the practice of inserting what you think is appropriate into rate base for the utilities of your state. And I honestly think we need to confront doing that affirmatively rather than pretending that we're not. That's my concern.

*Respondent 2:* As I said before, I think the markets aren't working. That's pretty clear from my perspective, and I think I speak for a lot of folks. I think Respondent 1 is correct. You know, we've got governors and others that are imposing their will, their point of view, on these markets. They're making decisions that impact the markets. So unless we can get some clarity from a federal level as to what the policy is, what our objectives are, I think it's going to default back to more regulation. And if we cannot get clarity on that, and it doesn't appear we can get clarity on that anytime real soon...

And so I think the answer is, you take a step back and you're really looking at some form of regulation. Now, is that the traditional vertically integrated utility? Maybe not, but maybe it's a model like MISO uses, where you've got the benefits of a market and you've got the benefits of broad dispatch of a lot of different resources, but the states also have some say in what that looks like, based on what they want to accomplish.

And right now we don't know what the objectives are. Well, people say, "I want to the Clean Power Plan target by 2030," but there's not a clear path in how they get that. That's not taken into consideration when they choose resources, necessarily. So while I would love for the markets to really work, these power markets are not real markets. They are hybrid markets, and I just think it's almost impossible to avoid some type of state oversight to keep things in a check and balance.

*Respondent 3:* I think it's a great question, and I'm not sure I know the answer to it. I'd like to think we're in a transition, and we can move towards fixing the markets. And I think it's OK for the states to be thinking about this and experimenting within the current legal constructs that are out there and are available to them. So it would be great if we could fix some of the ills of the market. It would be very nice to see if the benefits to customers can be achieved through a truly competitive market. As the previous questioner said, we're just nowhere close to being there, and so I think time will tell over the next couple of years whether this is a transition to get it right or a transition to move back to a vertically integrated type of system.

*Respondent 4:* It's an excellent question. I have a couple of thoughts. One is, when states in the past... (and I think New Jersey may have gone through this process. I know Maryland did. I think Maine did, and other states did.) With states that really did restructure, when prices were really high several years ago, when gas prices were high and the rate caps were coming up, people actually got to the brink of saying, "Let's go back and change the fundamental paradigm back to what it was." After looking at it, people didn't do that. States didn't do that, even when there was the political pressure, and there was the economic pressure, and I think the

proof is in the prices that are out there now, the wholesale prices.

I mean, there are problems with the markets. We're in the vanguard of addressing them, but if you step back and look and see where prices are in the wholesale market today, they're the lowest in New England they've been in 13 years. And that's not necessarily a good thing, long term, from a supply standpoint, but if you look at what's happening in terms of the demand response aspects of it at the retail level, and the distributed resources, I don't think we're at a point where we're going backwards is possible.

Unfortunately, unlike everything else that was deregulated in the 80's and 90's, there was not the complete separation that was done in trucking and telecom and everything else. So there have been vestiges of this hybrid kind of lurking out there, and that's what we've been trying to say-- whatever you've got, make it work. And I fear that if we don't make the right changes that we and others have proposed... It goes back to leadership and national policy. We need to figure out what we want on the environmental side, what we want on the electricity side and then stick with it. I fear that we're going to end up kind of going backwards into some sort of more regulatory paradigm which, frankly, would make EPSCA members better off, right? Generators today would love to get a regulated rate of return.

As I said at the beginning, this is the time when we should want the efficiencies and flexibility and risk shifting of the market and be taking advantage of these technologies that are out there, if we let this thing slide back it's going to be great for some of us, maybe at this table and around the room, and as Respondent 1 quite correctly said, there're people who aren't here who should be here, which is why we're starting to reach out. As I said, in this Ohio case we've

got this unlikely alliance with consumer groups and environmental groups.

Some things got to give in the next I think, six to eight to nine months where people are going to have to make decisions. Well, I think they're going to be bad, decisions, they're going to put the policy backwards on competition and we're going to be in the worse possible shape to confront the future challenges. So I wish I had a clear answer. I'm somewhat encouraged by what's going on with the Department of Energy. I'm somewhat encouraged, with a little bit of trepidation, that Congress is starting to get interested in this. But, really, those of us around this room and adding a few other folks, need to get on it pretty quickly because otherwise we are going to slide backwards.

*Respondent 5:* Let me just respond to that question and react to some of the panelists. I used to think in terms of transition, too, but in the end I realized that was actually not the right way to think about it. Because when you think about transition, you think of almost being in a race. You cross the finish line, and then you're running in slow motion. You have a runner's high and your work is done, right? It's over. And that actually is never going to happen. I also don't think the goal was ever deregulation. I don't think the goal was ever relying completely in market forces and wholesale power markets. It's always been relying on a mixture of regulation and competition. That mixture is going to continuously change. If you actually ever get it perfectly right, then it's going to be perfectly right for a brief moment in time, because the markets are highly dynamic. So the fact that PJM has made 25 changes to capacity markets...if they made zero, I would think that would be a much worse number than 25. I think that's the job of an RTO, to be constantly looking at their rules--how are rules working, what are the defects? I think it's much more an

indictment of an RTO when they are aware of a problem and they propose no solution than if they actually propose a solution.

So is it a hybrid market? I suppose it is, if a hybrid market relies on competitive forces and regulation, but I think it's always been a hybrid market. And so I don't take the changes in PJM capacity rules over time to be somehow an indictment, but I don't think the goal was ever deregulation. So I guess I'm disagreeing with some of my panelists. I guess is another way to think of it is that the transition never ends, and if a transition never ends, it's probably not a transition. We should call it something else.

*Respondent 3:* I think you're misreading me, if you think I meant that the 25 rule changes proposed by PJM are an indictment of the market. I think it's just a sign or an indication of what you've all heard today and what we, I think, agree on--that it's not quite right, and maybe far from not quite right. And so changes need to be made, and I was only suggesting that PJM and others know it, and when it comes to thinking about a state solution or a PJM solution, there's perhaps no right or wrong answer, but we all agree that the markets today aren't working. The PJM price alone markets aren't working for customers long term. I agree with you. They should be changing all the time.

*Respondent 5:* I don't think everyone agrees though, just to clarify.

*Question 7:* I actually have three questions. First, both Exelon and Dynegy, I believe, suggested that if the product that's been offered in Ohio is there, then why not bid it out for competitive solicitation and test the market, if you will, for those kinds of services. The next question is the question of stranded assets. Essentially, the consumers paid for this when it was rate based, or at least paid for some portion

of it. Presumably they completed paying for these assets when stranded assets were recovered. They were paying for some of it during a competitive market, and now aren't they being asked, in a sense, to pay a fourth time for the same set of assets? And then the the final question is, assuming the panelist's numbers are right and that if PJM retires these plants PJM is ultimately going to spend more money on transmission to fix the problems, is there a better way that PJM could handle that kind of situation that would obviate the problem without having to go back to the state of Ohio? So those are the three questions.

*Respondent 1:* Good questions, all of them. With respect to the auction, there's a role for auctions. I just would suggest auctions aren't the only way to determine the best overall solution for customers. It does not take into account a whole number of externalities, a whole number of other issues that consumers and regulators can take into account.

With respect to stranded costs, Speaker 3 and I are just going to have to disagree on what customers paid for and what they didn't pay for. Customers don't pay for power plants. Customers pay for distribution services, transmission services and generation service. When I buy my Ford Explorer, I don't own a part of Ford Motor Company. And the same way customers receive service from their utility company, they don't have an ownership interest in the asset of those companies. I mean, I'm not a lawyer, but I think that's just the legal answer to that question. A lot of folks have said that Ohio companies received billions of dollars for stranded costs. I've been looking for that check at the company for a long time. It doesn't exist.

When we deregulated Ohio it was the first time we delineated on our customers' bills, separate charges for distribution, transmission, and

generation. Residential customers received a five percent discount in the generation price for electricity, and the company had to write off the generation assets. And, again, there was no check from customers for those assets, for writing down those assets, paid for by shareholders.

Is there a better way to handle the example I gave? I don't know. I know it's an issue. I know customers lost in that equation. To the extent states can look at it holistically, as I think they can and we have proposed before the commission today, I think that's one way, but I'm not sure.

*Respondent 2:* As it relates to the New York situation, I just want to make a couple things clear. So while we've advocated for a clean energy standard, we advocate putting a price on carbon for all carbon free resources, not just the nuclear plants. What's been proposed by the state of New York is a contract for differences, which is basically a subsidy to bridge that gap for selected plants. We do not support that. We're not pursuing that for our plant. That's not what we asked for. What we support is a market based approach that puts a price on carbon.

*Respondent 3:* I think the first part of the question really goes to the heart of what's presently before both commissions. One claim is that the proposed change is needed for reliability and resource adequacy in the state, which, of course PJM and the Market Monitor and others in the docket showed is not the case. But if you're going to do this, as bad as it is, then it just stands to reason that some kind of competitive procurement process would then determine the least cost way of meeting that need. And the New Jersey example proves why you should do this on a competitive basis, if you're going to do it. So, the original proposal in New Jersey was for a specific plant, a specific

location, to get the one or two billion dollar subsidy, depending on the size of the ultimate program. And we and others said, "We think this is a bad idea, but if you're going to do this, do like you handle everything else, you know, computer, watches, desks for the school system, whatever, and put it out to competitive procurement." And what happened was, the original proposal that was being pushed politically did not succeed in the competitive procurement arena, and instead the PPAs went to others. So, while we thought the PPAs were a bad idea, at least it was done on the least cost basis.

As you correctly said in the docket you now have at least two competitive suppliers saying, "Well, if what you want is so many megawatts over a certain term, there's a lot cheaper ways to go about it." So there was no real rigorous analysis that said, "We need X, Y or Z megawatts, and let's go out and accomplish it." And that's precisely what the FERC affiliate rules in fact require.

So even in the absence of the statements of Exelon and Dynergy, the issue really is that under the FERC rules there should be competitive procurement. And I have to say, the idea that customers are benefitting from this...I mean, if you just look at who in the docket filed on which side...the Consumers Counsel, the Manufacturers, Citizen in Action, and AARP...and individual businesses. People writing into FERC say, "I didn't know what FERC was. I've never written to FERC before, but FERC should at least take a look at this." So I think that's why it's so important that the Commission does look at it, because there are these alternatives out there, and competitive procurement would be one way of proving whether or not this is the least cost way of accomplishing this, assuming you think there's a need in the first place. That's debatable, but if

you're going to do it, the competitive process is what should be used, as New Jersey did and Maryland did, and the results speak for themselves.

*Question 8:* I wanted to pick up on the point that the earlier questioner made about the importance of getting prices right, and so my question to the panel is about the degree of price distortion you see in the markets today and whether you think it's going to get worse. And the reason I ask this is that Speaker 3 had listed a set of interventions, renewable portfolio standards, efficiency investments, and at the federal level production tax credits and investment tax credits. So when you look at this hybrid that we've got of markets and these political interventions, and you assess the degree of price distortion, is it a little bit and it's going to be fixable and it's temporary? Or is it big and chronic, and with 20 years of experience you don't think we're really going to fix it as we go forward? Where do you see us on that spectrum right now? And could you comment on the points that people have made? They've called power plants uneconomic if they can't survive with current market prices. Is that hybrid market test really a valid measure of whether something's economic or not?

*Respondent 1:* With every and conceivable due respect to the previous questioner, there's no such thing as getting a price right. OK? It's not something out there you can find. The price for electricity is a political issue. It has to be universal and affordable. If you don't have it, you have severe health and safety consequences. OK? So we're not going to send out some marginal price or hourly price of electricity to residential customers. It ain't gonna happen. And then the question is, is the old way of finding the price, using a total review of cost and revenues and executive salaries and low income programs and efficiency and renewable...? It's at that point that the state regulators make

decisions about the diversity of their fuel supply. Whether it's from the wholesale market or from plants located within or outside their state jurisdiction, the issue is, is that generation supply of that product obtained in a way that is arguably competitive, in the sense that it's not due to insider trading? It reflects the state decisions about what they want on diversity. It reflects the analysis of books and records of actual costs and the profit margin involved and the whole kit and caboodle.

If that's the price that is politically acceptable, which it is in the majority of states in our land, you have to compare it to the hybrid system that is existing in the 15 or 16 real restructuring states in which we have this highly regulated wholesale market combined with a lot of state mandates that are imposed on the wrong part of the customer bill. Then I have a problem with that. So there's no magic way to set a price. It's a political decision as to what's acceptable in each jurisdiction.

*Respondent 2:* Respondent 1, can I ask you, would you prefer to go back to reintegration, where everything is done by vertically integrated utilities, and rate payers bear all risk? Even in the case of the nuclear cost overruns, something like 90 percent of those costs were borne by rate payers. They were not borne by the utilities. There was some disallowance, but it was actually pretty thin. Would you prefer going back to the old way?

*Respondent 1:* There is no way that's going to be perfect, or in which we could not find warts and problems. I'm having trouble, and I think many of the people at the table are having trouble, with this on again, off again approach. I don't know which world I'm in. Politically, I can try and get my uneconomic plants paid for by rate payers in a particular state. Why not go for it? I mean, I understand that incentive. But it's the

hypocrisy of trying to claim that what we're doing here is some benefit to customers in the long run. I mean, let's be honest with what's going on here. The way in which the states out West adopted retail or restructuring and then pulled back was that the plants that were gone, are gone. We're not going to buy them back again. And there is a wholesale market transaction going on there. And there are independent generators that sign PPAs with the utilities to meet their generation needs. So encouraging that kind of competitive approach, that makes a lot of sense. I don't think we need to go back to the issue of the utility owning everything.

*Respondent 3:* The short answer is, I'd say it's getting worse and likely to continue to get worse unless some corrective action is taken. The distortion was always there, to some degree, but it was masked when gas prices were so high and the clearing price was much higher, then the distortions weren't as apparent and didn't have as much of an impact. So my crazy Midwest analogy was always to the level of the creek. So when the creek level is high, you don't see the boulders and old cars and bottles on the bottom, but when the level drops down, you see things that were always there, but didn't have much of an impact if you're trying to float down the river. So I think that's where we are, and it's getting worse. It's going to continue to get worse for the reasons I think all of us are well aware of. In the meantime, we've got low to zero demand growth, which is a tremendous thing. There is the rise of new technologies, but that's going to continue to both put more pressure on the centralized plants, in terms of requiring ramping and so forth, but not compensating plants for that. And so all these pressures are out there, and decisions are made and have been made, at least for the 11 years I've been in this job, and I haven't come up with a solution yet, so maybe I'm not the right one to ask or answer

it. But there doesn't seem to be a score keeper or somebody who's actually looking at the accumulated impact of all these different policies.

I think everybody in this room knows the PTC and the ITC were extended, not because somebody got together and did a really hard analysis of what the impacts would be, and didn't take into account what it would do to say nuclear in the Midwest or other places that would be impacted, so you're not advancing the carbon agenda. When a nuclear plant closes in New England, from a pure carbon standpoint, it doesn't help to close nuclear and replace it with gas. So you can't say these things are all being done in a carbon direction.

But nobody's taking the accumulated impact into account, and so the PTC extension was simply a tradeoff to export oil. So that's great. Oil companies get to export oil to all over the world, and I'm all for that, but it just did wreak havoc now in the electricity system. There was never a discussion about it, so I think it's going to continue to get worse unless somebody says, "Timeout, halt!" There's a tipping point, and I think we're at that point now. And what's distressing (and I'll say this with some trepidation with some RTO folks in the room) is that it's taken us three years, we got in some minor things that FERC is changing, but the last thing that FERC did was require reports from the RTOs. And all we said was, "Please, at least say, reports and action items, deadlines, when are you going to do what you're going to do?" and almost all of them leave it at, "We have a stakeholder process on this" or "We have a stakeholder process on that." And so we're left with the situation where it is getting worse, but no one seems to be grabbing the mantle of leadership and saying, "This is what we're going to do about it, and this is the date certain by which we're going to do it." And in the absence

of that, as I said earlier, people around the table, around the room are going to have to make business decisions, and I fear we're going to slide backwards instead of forwards.

*Respondent 1:* Let me just say, one of the impediments to leadership and taking the bull by the horns is that we have state law on the books in these states that mandate retail competition, restructuring, and hands off the supply of retail suppliers who want to market to residential customers. And yet they all have, most of them, a statutory mandate that default service be acquired in a transparent RFP type process in the wholesale market with contracts that have fixed price, full requirements, laddered so we don't get a lot of volatility. And those laws are on the books, so the states are kind of hampered in terms of what regulators can do, unless they try to get together with their legislators and start talking about reforms that would allow more and more state control of the price of electricity. Not by buying back the plants, but by taking some steps to acknowledge that we're regulating the whole bill.

*Question 9:* Going back to what we heard from a previous questioner a while ago, he talked about the commodity of energy being fungible. Some people are selling energy. Some people are selling a service--safe, reliable, affordable, environmentally sustainable power at a reasonably predictable price over the long term. Those are two very different products. They require more than one kind of market, and we have more than one kind of market. We have short term centralized markets that are very much a price only, fungible kind of market. We have bilateral markets that will allow you to manage type, risk, value and share, those kinds of things. We have the competition from self-supply--the ability to grow your own or make your own if you're not finding what you need in the market. This works very well in other

industries, side by side. If I have a long term contract to sell bread, I might buy some of my wheat in the Chicago Mercantile Exchange, but I'm also going to be buying some under long term contracts, so that I get the right kind of wheat at the right times, and the right quality with the right risk management. And I might even grow some of my own. And nobody complains that growing my own wheat is interfering with Chicago Mercantile Exchange. Why are we spending so much time just talking about the centralized markets, and not talking about how they can work well side by side with bilateral markets and self-supplied competition?

*Respondent 1:* I think the short answer is, unlike the bread example, electricity is just physically and financially intertwined in ways that everything isn't. You know, you deliver bread in loaves of bread. In electricity everything's pulled and delivered through all the physics of the grid, which is what makes it so much different and more difficult. Well, we should strive, if we can, to accommodate as many different approaches as possible, but ultimately it's also intertwined, is the short answer.

**Question 10:** We've had out of market interventions since the beginning of the markets, and certainly the RPSes are examples of that. Is it that we've reached a tipping point where the incremental amount on top of some of those, let's call them historic interventions, is now causing distortions when matched with the lower gas prices? High prices solve lots of problems from a revenue standpoint. And how do you balance that with the fact that in PJM and in New England, in particular, we're still seeing substantial amounts of new investments come in at prices well below net CONE? You know that we've got three large new plants that just cleared in the last four capacity auction in New England at prices 73 percent lower than what it took to get a new plant built just three years ago in the

region. Where are we, maybe, on the lifecycle of the market, and is it a tipping point, or what is it that's leading to these discussions with a higher sensitivity now?

*Respondent 1:* That's a good question. I think the lower price of natural gas has really kind of put us at a tipping point. Those lower prices, frankly, are a blessing to everybody. Low natural gas prices are good. But it starts to then challenge the economics of some of the plants, and I think that's the main issue that we're seeing. The piece, again, that I say is missing is that we've got other objectives. Somebody mentioned everything being fungible. Well, it depends on what your objectives are, in terms of being fungible. For example, with coal fired generation, you might get the same delivered megawatt, but there are attributes associated with that that are different than natural gas, different from renewables, and different than nuclear. And I think it's a little naïve that that is not addressed. Because they're not all made the same, OK? They ultimately get delivered the same, and they're fungible, but how you create them is different.

And so natural gas prices covered up a lot of issues. But now the financial realities that people are facing, not just the nuclear business, but even other merchants, are that, based on these prices, they've lost a significant amount of margin and may be struggling for survival. And for some people, it's all based on your risk tolerance. So you've got new entrants in the market. They're bidding at prices that...frankly, in the last auction, we were surprised to see it come in at seven bucks a KW a month, you know. They're obviously willing to take on a lot more risk than other players. But this is a commodity where people expect it to be on all the time, and so you have to ask yourself, is that going to be sustainable going forward, in consideration of your long term objectives--

reliability, cost and environmental considerations?

**Question 11:** Ultimately, is part of what you're arguing for really a value based tariff or value based pricing? Because responding to the argument about energy being homogeneous, you know, when you look, for example, at solar PV, the problem is not the electrons themselves. They're not anemic. It is the inverters that export only real power and not reactive power, you know, that means that what's exported is not as useful as other stuff. So is really what you're arguing for, let's look at some of the values that we need, like voltage and bars and spinning reserve and other things, and once you have a value based tariff, you can really get to pricing mechanisms that get us to reliability and safety and just and reasonable rates?

*Respondent 1:* That's exactly right, and that's what we're promoting. Put the value on the attributes that are needed to support the ultimate delivery to the customer in consideration of your long term objectives. ERCOT's got a good ancillary services market that works pretty well. We don't see that same robustness of ancillary service markets across the country. And it goes the same thing of putting a price on carbon, et cetera. It's value based on the attributes.

**Question 12:** I wanted to respond to one thing Speaker 4 said. I don't read the EPSA decision as as reducing state authority. I think it's a strong decision in the name of cooperative federalism, and I see it an increasing role for states coming out of that.

So my question is, where do you all see the states going forward on things like the growth of distributive energy, energy efficiency, demand response? A lot of that is really happening at the state level, and I don't know how we can have any discussion about reliability or where the

markets are going without really recognizing that. What should the role of the states be, in your perspective? It seemed to me that the thrust of the discussion was that this should all be going towards FERC, and that we need the federal government to make a decision here. And whether or not people think that's accurate or not, I think the facts on the ground are that a lot of the activity is happening more locally and at the state level.

*Respondent 1:* I think you're right. I mean, I don't think there's a diminished role for the states at all. In fact, a lot of these questions, and a lot of what the states, utilities, regulators, and legislators are looking for, is best decided locally. And so I think you're absolutely right. There's no diminished role here for states. I haven't read that in any of the decisions. And you're seeing the states act, and they're reacting to the question the whole panel started with. Is it, "Aw, shucks, tough luck, your plants are shutting down because they can't compete in the market?" Or is it, "Time out. Wait a second. This market's flawed. Shouldn't we fix the market? And then maybe we can determine what plants survive and not?" But if we have a truly competitive market then I think it's right to say, "Well you know, maybe whatever happens, happens." But even then there's a state role for those kind of decisions at the local level.

*Respondent 2:* I think it's a really hard question. I would love to think that somehow we're going to get clarity from the Supreme Court on what the respective federal and state roles are, and we will probably get some negative clarity on what states can do, but that boundary is going to remain uncertain. In my pessimistic moments I think that FERC states are sort of doomed to some level of conflict in the area of resource procurement. I'd like to think that's not true, but it might be inevitable because states and FERC are both discharging legal duties under different

laws, but there are overlapping responsibilities. And fair minded people discharging different laws actually can sometimes fight with no bad intent involved. FERC, I think, has gone a long way to try and accommodate state policy goals, but sometimes they can't. One case where I actually think they went too far was in New England, where they allowed the renewable exemption from the capacity markets, even though there was some evidence on the record that it would result in a nine percent effect on capacity prices. And nine percent is not a small number. That's a lot bigger than FERC's manipulation cases. I don't think any of those cases involve a nine percent price effect. But FERC allowed it, notwithstanding that un rebutted evidence, because they didn't want to discourage a laudable state policy goal.

But sometimes the state goal is more nakedly suppressive in design. FERC should naturally fight those, but then they'll be some in the middle, where there's actually a facedly legitimate stated goal, but it's not the real goal. And I'm not trying to attack states, but I remember New York, many years ago, had a scheme using dormant commerce clause cases, where the goal was to lock up the New York City market for New York milk farms. And so they basically said, "Well, to protect children and make sure children don't drink bad milk, milk can't travel more than X miles from New York City." It turns out that completely encompassed the New York Dairy farms, so there, you know, there was a facedly wonderful goal, but it wasn't the real goal. And the courts ended up striking it down.

But it's harder in the middle, where there is a totally legitimate stated goal, and either it's not the real goal, or it is the real goal, but the effect is nine percent or greater. And there I think that if there's a legitimate goal and a real goal, but the price effect is significant, I think FERC

probably should still act, and hopefully states would realize it's not because FERC enjoys disagreeing with states, but it's because it's different duties require it to do so.

*Respondent 1:* I just think it's very dangerous for FERC to be in the new game of calling balls and strikes on what legitimate state programs are and are not.

*Respondent 2:* I would say it's not a new game. But I understand what sounds like --

*Respondent 3:* They're enforcing federal law.

*Respondent 1:* You're right on that too.

**Question 13:** I'll try to make this quick, but just a quick story and then a question. I remember when we were restructuring in Ohio sitting in the office of a state Senator, and I remember telling him, "Look we're not doing this to lower rates to consumers. I've got all the tools in my regulatory toolbox to go back to my office, update rate of return, and I could lower rates right now." The reason for doing restructuring at the time was risk allocation. At the time in Ohio, we needed peaking plants. How could we get those built? How could we retain plants, not just in the traditional model of sort of all on the risk on the consumer? So my question is, that was the goal, where are we today on that question? If the Ohio PPA plan is approved, what does that mean for this fundamental paradigm that we were trying to do, or was it a pipe dream in the first place, and we never should have tried to insulate customers from that risk?

*Respondent 1:* I don't know if that was the goal. I mean, what happened in Ohio is not dissimilar to what happened to a lot of the regulated states. For the first time in the nearly 100 year history of our industry, we had a great disparity between prices paid by customers. Those customers who

were served by utilities that built nuclear power plants after Three Mile Island had big price increases coming. And those that didn't had lower prices, and it was the industrial customers in Ohio, clearly, who said, "Wait a second. We can't sustain having a steel plant here in one part of the state compete with a steel plant here in another part of the state where the price differential is two, three cents per kilowatt hour. It can't happen. We need to deregulate. We need those generation prices to be the same overall." At least from my perspective, that's what pushed Ohio to deregulate. And they did it in a way, in Senate Bill 3, that was very similar to Pennsylvania. And then, under Governor Ted Strickland, Democrat, when power prices were

soaring upwards (remember the 72 percent increase in Maryland?), we passed Senate Bill 221 which created the current hybrid system we have today.

*Respondent 2:* The quick answer is, you were right. It was about risk allocation then and it should be about it today, but we're running the risk of undermining that through what we talked about this morning.

## Session Two.

### Stakeholder Processes: “The Worst Form of Government, except for All the Others”

*Organized markets under Regional Transmission Owners need a stakeholder process to consider and analyze all manner of reforms and improvements in market rules and operations. Although not strictly a democracy, the analogy is apt about the promise and complications of any governance mechanism that respects and draws on different or competing perspectives. The different experiences across RTOs allow for an examination of the functioning of stakeholder processes. How well are stakeholder processes working? What are the major examples of success and what are the examples of challenges? How have stakeholder processes evolved over time? Have stakeholder processes created so many committees and meetings that only the best funded of stakeholders can really influence outcomes as opposed to those with the best ideas? Have the stakeholder groups become more inclusive or exclusive? Who is the stakeholder that represents efficient markets? Are the RTOs susceptible to lobbying pressures and capture by certain interested stakeholders? What are the lessons and major opportunities for improvements? Are the processes too cumbersome, or just cumbersome enough?*

*Moderator:* Good afternoon. Welcome to our afternoon session of the 82<sup>nd</sup> session. The title of our session, of course, is “Stakeholder Processes: The Worst Form of Government Except for All The Others.” Also known as the “Stakeholder Processes: You Can’t Live with It; You Can’t Live Without It.” So, with that, we have a great panel today. We’re going to switch the order a little bit that’s in front of you because we’re going to start kind of from the RTO perspective from the inside, then the RTO perspective from the outside, a somewhat academic look specifically at some of the analysis that’s been done, and then kind of a customer of multiple stakeholder processes.

#### **Speaker 1.**

Thanks very much, and thank you all for inviting me and giving me this opportunity to be part of the panel this morning. Stakeholder processes are really important. They’re very important to all of the things we talked about this morning. They’re important throughout all of our operations. Why? Because they address the rules

that are vital to how we provide electric energy to all Americans, essentially.

As a reflection of the importance of the stakeholder processes, they seem to be unifying in only a few ways: one is that most people hate them, most people think they’re broken in some way, and most people want to change them in some way. I think it’s a good thing to do to step back, perhaps, and take a look at some principles about, why do we have stakeholder processes? What do they accomplish? Take a look at whether they’re functional or not or in what ways are they functional, and in what ways are they not functional, and then what are the alternatives?

Perhaps we can look originally at PJM as a case study, and take a little bit of a history lesson, if you will. The PJM stakeholder process really does have a rich history, and it’s evolved dramatically over the course of time. Just like we heard this morning about capacity markets in particular not being static, with so many changes at least within PJM’s capacity market space--25

or 52, depending upon how the count was done - stakeholder processes are not static either. I'd argue that perhaps they shouldn't be static.

With that, let's take a little bit of a look at PJM. PJM has, as everyone knows, grown dramatically over the years. PJM, from its initial institution with the power pool starting in 1927, actually did have a very nascent form of stakeholder process. There was an operating committee that existed and morphed into a management committee over the years with the growth of PJM, up to its 14 constituents in the late 1980s/early 1990s, and then after PJM morphed over to the LLC in 1997, we saw it grow really significantly, everywhere from 200 members in 2002 up to over 960 members now.

Let's take a look at some fundamentals for PJM. With respect to our stakeholder process, we have what I affectionately call the Big Three Governing Documents: we have our Operating Agreement, our Open Access to Transmission Tariff, and our Reliability Assurance Agreement. To be sure, there are other governing documents within PJM; things like our Joint Operating Agreements with our neighbors, we have implementing documents like our manuals and so forth that get a lot of attention, and our Transmission Orders Agreement, and so forth, but with respect to our stakeholder process, these are really the big three.

I think it's important that we take a look at the Operating Agreement in particular to start off. The Operating Agreement really is the corporate foundational document for PJM, LLC. It sets up the LLC as the office of the interconnection governed by an independent board of managers who are elected by the members of PJM. There is this Members Committee, which, for those of us who are non-attorneys, you can think of perhaps as similar to the management committee

of a partnership group. They have the ability to be represented on that management committee, all the member companies do, and have the ability to have a certain level of decision-making authority. A couple of points I want to make here that I think are important is that all of the governance of PJM is included in the Operating Agreement. There are a variety of corporate foundational principles that are in the Operating Agreement. There are also a number of more technical market and operational aspects that are included in the Operating Agreement. All of our market rules are in Schedule One to the Operating Agreement. For example, the RTEPP rules, or Regional Transmission Expansion Planning Process rules, are in the Operating Agreement. Why is this important to you, and why do I bring it up? Well, it's important because that is an agreement amongst the members of PJM. Remember, to be a member of PJM, basically to do business in this field in PJM's footprint, you have to be a member of PJM. So, if you're a member and signatory to the Operating Agreement, you get a say on that management committee, if you will, on the members' committee. It's also important because when we look at the Federal Power Act 205 and 206 rules, that members' committee retains the 205 authority over changes to the Operating Agreement, which includes the Energy Market Rules. Conversely, the Open Access Transmission Tariff rates and terms of service, the 205 authority for the OATT and for the RAA, rest with the Board of Managers as the regulated public utility, the Board of Managers managing the Office of the Interconnection.

Where's the rub? The rub is that the Energy Market Rules are in both the Operating Agreement and the Open Access Transmission Tariff, so to get something filed under section 205, to change our Energy Market Rules, we need to have both the Members' Committee and the Board agree, vote in favor of a specific

change. It's important. It's complicated. It's difficult.

Why do we have a stakeholder process? We do a lot of things there. To be sure, with over 400 meetings a year...and when you see the organization chart of our stakeholder processes, you'll see it's complicated. We do a lot of things: we educate each other; we explore solutions; we communicate, but the bottom line for our stakeholder process is to vet, approve, or endorse, depending on whether you own the document or not, changes to the market's operation and planning rules as codified in those big three governing documents in PJM.

So, how do things work? To keep things in perspective, the stakeholder process is only one portion of the process that's necessary to get a change to our rules implemented. Everything from somebody coming up with the idea, getting through our stakeholder process, the agreement of our Board of Managers, a FERC decision, potential compliance directives, and potential challenges in circuit court, as we've seen recently.

How did it work? Well, as I said, we've evolved. We've morphed over time. After the 1997 implementation of the LLC, we had a process that in retrospect, if you remember School House Rock, it looked a lot like, "I'm just a bill on Capitol Hill." Somebody would come up with a proposal for a change and then bring it to a committee within the PJM structure, and suggest the change. Somebody else might try to amend that. Somebody else might bring their alternative bill, if you will, and we would essentially discuss, argue, vet what might come out of that with very little in the way of specific rules on how to do that. Over time, we morphed.

I should mention there's an undercurrent underneath all of this which we'll talk a little bit

more specifically about in a moment, but something that we've called the balance of power or some call the balance of terror within our stakeholder process which is, how do we make decisions? How do we vote? It all comes down to rules for voting and what constituents within the stakeholder process carry what weight in the voting. We'll talk more about the specifics of that. That concept of how decisions are made, who votes, the weighting on the voting, has led over time to evolution of how our stakeholder process has worked. If you look back to that big three governing document diagram that I showed you a moment ago, recall that the Operating Agreement is where our governance rules are found. You'll note that our governance rules for the stakeholder process are all bound up with our corporate governance rules in that document. They're somewhat inseparable. The voting rules are also included in that document. As you'll find later, if you want to change those voting rules, you need what we call a sector-weighted vote to change the sector-weighted vote and the weights. So, nobody's going to vote to reduce their own voting power. Over time, people have recognized that and, in an attempt to address it.

Recognizing that stakeholders are sometimes not going to be able to make a decision, to make a rule change that might be necessary in some fashion, and our board might find the need to make a filing to make a change, our members have looked at that situation and said, "Well, how are we going to influence our board? What are we going to try to do to rectify this potential impasse situation we might get to in our stakeholder process?" What they've done is try to adjust our processes to get to a place where they might be able to reach consensus. The most recent time we did this was in the aftermath of FERC Order 719, when we had the board responsiveness to stakeholders requirements. The members looked at that and said, "How can

we influence the board when we don't come to a decision?" They decided that wanted to embark on an update which would be consensus-based, and ended up with something we call now the Consensus-Based Issue Resolution Process, which we can talk about in more depth, but it originates with agreeing that we've got a situation that needs to be addressed, and not just somebody bringing a bill, and then working through a structured problem-solving technique that's aimed at consensus with mutual gains. We can explore those later.

What does it look like? It includes a significant amount of education to bring all of our stakeholders up to a minimum level of understanding of what the problems are that need to be resolved, development of a proposal in a structured fashion, some decision-making, and a significant amount of reporting out. I mentioned the org chart; it's an eye chart really, but I want you to just take a look at colors here. That central area with the mustard, Carolina blue, greens, and grays, that's where the stakeholder process works. The blues are informational areas. A very important part of our stakeholder process is the protection of rights for minority interests and that's it the magenta color to the left. That's the opportunity for folks who aren't able to address a needed change because they find themselves in the minority of stakeholders' interests, to have the ability to bring changes as well. We can talk more about that.

Voting. I mentioned voting is complicated. It represents complications. The actual voting is fairly simple. Every sector in our membership gets 1.0 vote apportioned amongst those who vote for and against. Folks at Harvard and MIT who did some work with us earlier helped us to understand. They call it truncated approval, super-majority voting. "Approval voting" is yes or no; "truncated" is you vote on proposals in

order until you get one passed, and once it passes you stop; the "super-majority" is you need two thirds of the total of each of the sectors voting in favor of something for it to pass. But note that each sector only gets 1.0. We can explore that later under questions.

Some of the problems that we see or the complaints that we hear from folks are around the diversity of our membership, the number of members in each sector who can cast votes, the participation of those members, and whether or not the members within a sector are homogeneous and represent similar interests. Our members recognize that we couldn't get stakeholders to agree on occasion, and what do we do then to influence the board if it decides it needs to make a decision absent stakeholder consent? They've developed methods to share information with the board, everything from reports on who voted how and how the different sectors and types of members break down on votes, everything up to and including what we did with our capacity performance, which is our Enhanced Liaison Committee process that many of you are aware of.

Just to share a few observations with my remaining time, the number of issues that we have addressed through the development of individual problem statements at PJM since we implemented this consensus-based issue resolution process is significant. We've done over a hundred; I think last count was 114 individual problem statements since 2010. I would say the majority of them are focused in the markets area rather than planning or ops areas. Not all of them have come to consensus. Some of them have stopped, and nothing has come out of it. The majority of them have gone through to some level of consensus. A few of them have gotten to the point where we needed board action, and had to take action absent

consensus. We've had positive and challenging experiences.

I'd like to make a couple of observations just to close out. First, over time, with the evolution of the markets, the evolution of the issues that are brought up, we've noticed changes in behaviors. If you look back to shortly after the LLC was implemented, we were looking at big things, implementing LMP, implementing day ahead markets, and so forth. Those things were in retrospect fairly easy for people to get their heads around as good ideas to do. Sure, we argued about how, but we were able to get to a greater level of consensus on the bigger issues. As the markets have evolved, and we get down to mostly incremental changes to them, stakeholders can look at those incremental changes and value whether they're going to be an advantage or a disadvantage and how much. Then they'll take a look at that in their voting behavior. We have to recognize that that's rational. They have a fiduciary responsibility to their shareholders, their stakeholders, to look out for their company's best interest, and how do you separate out that company's best interest from the market's best interest? We see polarization that accompanies that.

We see things like comments from our stakeholders saying, PJM doesn't take aggressive enough action on one side; PJM takes too aggressive an action in other cases; our thumb's on the scale or we're not doing anything. Some say it's too rushed; some say it's too inefficient, but the bottom line, I think, is that certain things make everyone crazy-- capacity, cost allocation, and voting, so thanks.

**Speaker 2.**

Thank you. First, thanks for having me here. I'm going to try to talk through just how the stakeholder process works at the CAISO to actually get something in front of the

commission, in front of FERC. There's a whole information discussion that's a whole other topic, but getting stuff from the idea to submitted to FERC is what I'll focus on here.

We've had the same basic stakeholder process since we went live in 1998. The board's changed dramatically; we originally had a 26-member board of stakeholders that was revised around 2000 to about 5 "independent" board members, and that's currently the structure. In stark contrast to PJM, we don't have a formal voting or ranking or rating structure from our stakeholders.

Initiatives typically originate from the ISO and are put out to the stakeholders. I'll talk about how that happens. Sometimes they are ISO ideas; sometimes they're stakeholders' ideas. The ISO decides how to initiate it, in California. In my opinion, we have a very robust engagement process. There is a lot of in and out and give and go; lots of white paper and more details. After all that process happens, it makes its way to the board for action. If it's approved, it goes on to the commission for another set of review.

So I'll talk about that process. As I struggled in thinking about the democracy as being "the worst form of government except for all the others," I struggled with how to characterize our process in the ISO, and I came up with a short description. I think each word matters here. It's a "well-informed, benevolent and unified oligarchy." There really is sort of a core decision-making group, but to date, they've been acting, in my opinion, very principled and to a large extent very much aiming for the right objective at the end state. I view them as very well informed in this process. The oligarchy is not being capricious at all; they're being very well educated. We'll talk about how that education process happens, but there isn't that

sort of hierarchal or structured participation. It really is a decision by the ISO about when things actually make it to their board, when they're ready to go.

I sort of stood back and said, if I was trying to design principles related to what would be a good stakeholder process, one where I think people could stand back and say, "That's fair, that's reasonable, that's going to get the type of information and the representation that's needed to make good decisions," what would some of the attributes be? I'd say, first off, the process would be accessible. People would have access to this process. There's transparency to the process. Big or small, there's an opportunity to engage in what was happening. I think our ISO does a good job on that. We'll talk on that. Next, there'd be some sort of prioritization. Here's maybe where the oligarchy comes into play. There are some issues that have no material impact, and there are some others that may be good ideas, but there's only so much you can do in a day. There needs to be some good prioritization, where people step back and say, "That was reasonably prioritized." It may be on issues of dollars; it may be on issues of removing discriminatory processes, even if there aren't as many dollars involved--but good prioritization.

Aligned with "accessible" is "inclusive," that people should have the opportunity to contribute, propose enhancements, participate in the process. I think we do an OK job there.

Next, and here's where I think we struggle a bit, there are an amazing number of talented folks in this industry, and sometimes there's some really good complex ideas and sometimes there's just some really complex ideas, and deciding which one is realistic and worth the effort really takes that debate. It really takes getting dirty and really talking about how it's going to work. We

should be looking for good approaches, and not letting perfection stand in the way of implementing. Something that's good may be good enough, maybe not perfect but good, and moreover, something that can be achieved in a timely manner. This one maybe we struggle a little bit with within our process. There area lot of creative ideas, but sometimes a little too creative in my view.

The importance of balance. Not only should you be looking at the potential benefits of anything that's on the table, but far too often the risks associated with doing this aren't weighed heavily enough, and it's really up to concerned participants to ring the bell of risk and say, "Hey, there's more in play here than just the good side. Is this a balanced approach? Have we considered the risks? Also, have we considered, not just the implications to the oligarchy, but the implications for the stakeholders? Am I going to have to spend 10 million dollars to update my systems to accommodate something that I'm not even going to use, but I need to be able to settle with you?" There needs to be a consideration of pros, cons, and overall impacts, making sure you come up with a balanced solution to that.

Stepping back: the question of principles. What are we trying to achieve here? Is there a noble goal for all this? I'd argue that the noble goal is an efficient, non-discriminatory result, and that may result in winners and losers. People need to recognize that sometimes there are zero sums. Oftentimes there's not; oftentimes there are overall gains and many people have benefitted, but those seem to be the principle results of getting efficiency in a non-discriminatory manner. That can be difficult when there are losers. It's usually not that difficult when there are only winners, but when there are losers involved, that's difficult. So, to the extent possible, being principled in making these decisions is important.

The bottom, bottom, bottom line is it has to be legal. As much as we may have some great ideas, they have to get through the commission; they have to be just and reasonable; they have to pass scrutiny, jurisdiction, and all the other laws. We can't violate the law. Sometimes we change the law, because we see there are opportunities, but it has to fit within that framework.

I think whatever structure you have, in my view, this is a reasonable checklist to say, do you have a process that's achieving these? Others may have views, but I thought this was a pretty good list. If you could accomplish this, you've got something that's pretty workable.

I'm going to deep dive a little bit into the ISO stakeholder process in hopefully not too gory detail. One of the things the ISO does is every year they have an annual open season for ideas, and they have a catalogue process. This catalogue process is kind of like that tax code: it just sort of keeps growing and growing and growing. There are only so many hours in a year to work on it, and you have to prioritize, so there are a lot of good ideas that we just can't get to, but it has to be prioritized.

Some of our folks say, yes, the stakeholder catalogue is where all good ideas go to die. I don't think it's quite that bad, but there's just too much to do. There are too many issues. But the ISO does have a process to at least try to gather them and once a year to go through the yearbook and remember those ideas. The market evolves, and we do find ourselves at times looking back and saying, "Yeah, that idea was really the last war; that's not really what we need to do anymore. Things have moved. Maybe it was good we sat on that idea because it's really not relevant."

This process informs the ISO, but then the ISO decides on its own what issues it's going to tackle with its stakeholders. Often they're FERC mandates, and I'd like to say that those get top priority, but sometimes there's some strategy, because really we don't think that's just a great idea, and it grows old, and eventually they'll be a waiver request, and, again, the markets evolve, and what was appropriate at one time may not be relevant to what we're facing at another time, and sometimes they are taken on and sometimes they're not. If they're not, they get addressed. Often it's more a perspective the ISO has that they'd like to see going.

Then they engage the stakeholder process. Typically, they'll have some sort of issue paper; it's like, "Hey, this is an issue that we think needs to be addressed." Often there won't be a proposed solution; it'll be, this is the issue, and they get feedback on how other people see the issue. There are usually at least two sides to every story; they want to hear all the angles to it. Then, through this engagement--everyone's allowed to participate. I mean, it's public. They'll have public stakeholder meetings, phone calls. No one's barred, and so far it usually works. People get involved and get their voices heard, and at least recognized.

Then after that there's usually a formal proposal. There'll be a paper that says, "Hey, this is how we plan on fixing it." Then there are some iterations. They get a lot of stakeholder feedback. We have a thing called the Market Surveillance Committee that I'll dig into. Usually the Market Surveillance Committee get roped in pretty early in the process and I'll talk about that. It gets some very powerful feedback. With the Market Surveillance with the stakeholder feedback, they come up with some flavor of draft proposal and usually get some more feedback on it and then a final proposal. That proposal makes its way to the board for

approval. If your voice wasn't heard in this process, in my view it's your own fault; there was plenty of opportunity to get up there to make sure things were recognized, a good transparent process with lots of opportunity for engagement.

About the governing board, as I said, we re-did it after the original process, and the board really is independent, but is selected by the Governor of California and approved by the Senate. So, yes, it's independent, as in it has no stakeholders on it, but it does have a California centric orientation and it is conscious of California policy. The board engages at various stages; sometimes very upfront to drive some issues, sometimes in the middle, and sometimes at the end, but by the time something comes to the board, they're very well educated, they're informed on where positions and things lie, and they know what's happening. I didn't remember the last time a board rejected something, and I really struggled, and I've been in the business a while, so I had us look back and see what the board's voting record had been for the last handful of years. The middle column is how many motions they've approved and the right-hand column is how many were unanimously approved, and you'll not they're identical except for one star. Now, that motion eventually passed. There's a couple ways of looking at this data, but I'm going to look at it in the most positive light. This is reflective of a well thought out process in which controversy has been addressed, and when an issue gets to the board, it's baked and the board members are comfortable with it, and it's so good it's a unanimous slam dunk and we move on. So I'll argue for the positive side.

Now, to test that hypothesis, I have to say they have a pretty good record at FERC. If they were rubber-stamping junk, we'd see a lot of stuff coming back. We don't see a lot of stuff coming

back. By and large, the stuff is pretty well received at the Commission; there are exceptions, but, by and large, it is. So I'd say by the time it gets to the board, it's too late to change it, but I will add that there is public comment to these boards, and that tends to be some of the funnest part of the stakeholder process--the pontification in front of the board, the last chance. Occasionally, there are modifications around the edges, but it's pretty much over by the time it's made it to the board.

Turning to the Market Surveillance Committee; this is really a hidden gem in our process. We have a set of academics and professionals in the industry that are nominated by the CEO of the ISO and serve staggered three-year terms, and they really know their stuff. The ISO engages with them, and I've heard it referred to from names not to be named as going in front of a Ph.D. dissertation board. So you're going up there with a proposal and you're in front of this board and you better be able to defend it. They ask hard questions. They understand how it works. I think it's really valuable. It's a really good way to sharpen the process. They're regularly involved, sometimes behind the scenes and sometimes very much in front of the scenes, with formal papers and the like and sometimes even into the public comment time in front of the board. Just to touch on it in this house, I wouldn't be surprised if many of you know some of these names: Benjamin Hobbs, Jim Bushnell over at Davis, Scott Harvey, who's been in the industry, some of our previous board members Frank Wolak over at Stanford, and even Peter Crampton here in Maryland. A real all-star team. This is a really, really, like I said, a gem that we have. Really insightful folks that understand the markets and understand the economics and the mathematics behind our machine. It's very complicated. This is one of the sort of secret weapons I see in our process.

OK, I just have a few minutes, but looking forward, the ISO is expanding and already has expanded its real-time market to about six other states. I think when we're done we'll have eight states, if everything goes as planned, and trying to get that to be a full-blown expanded RTO eventually. Right now, it's just the Cal ISO with the real-time market it's running. That's causing governance issues. That's causing stakeholder process questions. The board recently voted to approve what I'll call a sub-board for the EIM entities, where they get to approve items that are exclusive to the EIM market, but not the rest of the ISO. How large of a set of issues that is is yet to be determined, but they have that jurisdiction. But, still, the main ISO board will have to approve anything that they've recommended. This is also raising questions about whether this current stakeholder process will work, whether this sort of open, non-voting, non-structured process will work as we expand the footprint regionally. I don't know. We'll see. I think there's a lot of good practice in our current situation that I'd hate to lose.

Wrapping up in my daunting 30 seconds, the process is producing reasonable results, in my view. It's not perfect, it's not perfect at all, but this success is really heavily dependent on the commitment that I see at the oligarchy level of the ISO to adhere to many of those principles of reasonableness and some of the checks and balances that we have. This structure doesn't guarantee good results. Just like a benevolent dictator—yeah, if you can find one. We do have a good situation right now, but I won't argue that this structure guarantees good results. Regional expansion is going to create issues. OK, on that I'll end. Thank you.

**Speaker 3.**

Thanks very much. I'm really happy to be here today because I've been having conversations with many of you in my head silently for years

and the fact that we're all in the room together just makes me feel great.

I've given talks on RTOs now over about 40 times to groups, and they're I think the most interesting, not well understood, public policy organism that's alive today. When I talk to people who don't know anything about RTOs, A) they first don't know they exist, B) they don't know what they do, and C) they don't always know why they should care. So, you people know this.

When we first got interested in RTOs, it was in the context of looking at market rules for a pumped hydro energy plant in Northern Minnesota. When we were able to have that plant participate in ancillary service markets, we increased its value by 40%. When we changed the market rules from MISO rules at that time to ISO New England rules, we increased the value of that plant by 240%.

So, these rules are socially negotiated; they're not handed down by Moses or Bill Hogan on stone tablets from the mountain, and understanding [LAUGHTER] how these decision processes work was something really of interest to us. When we talk about the three tasks of RTOs, one thing that I hadn't really appreciated before starting to study them was how they really reflect those of traditional utilities, where you have a group of people concerned with reliability, a group of people concerned with the markets and the operations, and a group of people concerned with the long-term planning. The same tensions that you see within the utilities between the reliability guys, who always consider themselves the ones wearing the white hats, and those evil market people is really interesting. For most people who don't think about RTOs, understanding that they don't know about them because they exist at the

high-voltage transmission level with generators is something that they think about.

The other piece that I think is interesting for people is the fact that the value and the price of electricity vary over space and time, and how we can think about that, not from a wholesale perspective but also from a retail perspective, too. You've all seen the maps of RTOs.

The study I'm going to be talking about today, and I'm going to focus on the MISO region, but this is a National Science Foundation project with my colleagues Seth Blumsack and Penn State, Natalie Nelson-Marsh who's now at Portland State, and Dave Solon who is at Boise State. The study funded through the National Science Foundation directorate on the study of organizations. We've looked at decision-making within PJM, MISO and CAISO, and when we originally put the study together, we were going to look at transmission planning for renewables, kind of thinking about FERC Order 1000 and the integration of variable renewable resources into the operation of the grid. It was a very elegant study design. When we started going to the RTOs, we realized that this wasn't the conversation they were having, and we had to kind of throw that out.

So, we have studied PJM, and we've studied CAISO as well, but today I'll be talking to you about the MISO region, in particular how they manage this process of long-term transmission planning and integration into the grid, because I'm really focused now on policy implementation and practice. One of the things that's become clear is that each of these RTOs has a really different culture and a really different way they approach problems. We've talked about the different stakeholder processes with PJM and CAISO; MISO is no different.

When you're thinking about RTOs, thinking about whether they're single state or multi-state, appreciating whether the states are traditionally regulated or restructured or whether they're Texas, all of these things really shape how the world works. So, within the MISO region, all of our states, with the exception of Illinois, remain traditionally regulated, and the relative power of the public utility commissions in the decision-making process within those states is very, very important. At this point, we've interviewed almost 50 people; we've sat in on stakeholder meetings; we've participated in the calls; we've reviewed lots of different documents, and then we've gone back to the RTOs to kind of share our findings and help us interpret them. When you're thinking about who's involved in making decisions within the RTOs, how these stakeholder processes work in practice is particularly of interest to us. Everyone is equal, but some are more equal than others. Thinking about how that plays out within the stakeholder process, but also the planning process and what role FERC plays within this process and then if that doesn't work out, the federal and state courts, I think is very interesting. As the previous speaker mentioned, some issues are easy and other are perennially difficult, so understanding where tensions are for issues like transmission planning, which I'll talk about first, is the difficult issue, and then changing the operation to create the dispatchable intermittent resources program in the MISO was relatively easy by comparison.

Then, of course, what role civil society stakeholders play is a question that came up in the earlier panel today, also. I'm going to be talking about wind. This is the Charles Brush first windmill; I can send you the article, *Scientific American*, 1890. Here's your original distributed energy resource system. In the basement of his mansion, he had batteries to power his lights. Here's early American

electricity. When we're thinking about wind implementation and practice, wind in the MISO region has been particularly interesting and important. In part, we have great wind resources in the middle of the country; you've all seen this map, I'm sure. State regional renewable portfolio standards have really driven the construction of wind resources. We have 14 thousand megawatts of wind across the MISO footprint, with about that same amount planned for the future.

Now, early on in the process, the states became very aware that if they did not address the transmission issue from a regional perspective, that these state policy goals were not going to be able to be met. So, you had the Midwest Governors' Association pushing the first planning for transmission across the midwest region. In parallel with the MISO, they began to plan and think about how transmission resources could connect the different areas that were fruitful to develop for wind. But this question of cost allocation and making sure the wrong people don't pay for the right rules came up again and again and again, and the political process, as it was negotiated across the MISO, was really important.

Academics and engineers dream of a seamless, high-voltage, DC overlay that will make all market prices equal across the footprint. But in reality, we know, building transmission lines, especially multistate transmission lines, is much more difficult. One of the things that comes out again and again is how, through the process, you can negotiate and share these costs across a region, and I want to highlight that within the MISO region this was particularly controversial.

The history of transmission line build within this region of the country was quite controversial, and going through and creating a multistate project was something that wasn't for the faint

of heart. We have interviews with people from the utility sector who began to build these together. They said, "On my watch we're not going to have farmers running down transmission towers with their tractors," so this is what you ended up with. Across years of negotiation with the UMTDI, the Upper Midwest Transmission Development Initiative, 17 lines were approved across the MISO footprint, costing 5.2 billion dollars. MISO had watched PJM trying to do regional transmission planning once, having it go up to the Seventh Circuit and fail and come back down, and MISO said, "We need to do this differently."

So the political negotiations within this process were actually quite hard and quite controversial, where you had the transmission owners at one point threatening to leave and go file at FERC on their own, but this politically negotiated deal for the time helped. Many of these lines are being built now, but it remained really quite difficult. When you talked to people at MISO, and ask them whether, with their new expanded footprint, they could do this again, most of them don't think they could. So, again, one of these controversial issues.

I just want to highlight and contrast this with an issue that was relatively easier. Within the MISO footprint, you had a lot of wind being curtailed because of insufficient transmission lines. To curtail that, the operators had to call up the operator and say, "I need you to dispatch down." When wind was small, this wasn't a problem. When congestion cleared, you were allowed to come back on to the market. The idea of how RTOs were managing wind when wind was small was fine, but you had advances in control system technologies, you had wind growing within the footprint, and you needed to somehow institutionalize wind like any other resource on the market. So, together, they developed the dispatchable intermittent

resources program that involved that education component, where they spent time, you know, talking about and educating the stakeholders. First, asking all the stakeholders, “What are the issues that we need to make sure that we address within the MISO footprint?” So from 2009 to 2010, MISO had a wind integration initiative where they went through and asked everybody, “What do we need to do?” Then they made a list of issues that needed education. One was wind integration and planning. The other was how curtailments are handled within the system today. From that, they developed ten motions. These motions were examined by the market subcommittee, the reliability subcommittee, the planning advisory committee, who over the next two years all developed different positions, finally filing with the FERC in 2010 the DIR (Dispatchable Intermittent Resource) Tariff.

One thing that I think is interesting within the MISO footprint is, now, any one plant that is newer than 2004 (which is over 80% of wind in the footprint) automatically bids in to the day-ahead market, but it’s tried up ten minutes before it’s dispatched, so it actually makes its mark at clearing--and the negotiation of those rules happened through all of these committees. So now, no longer do the operators have to call up the wind plants. These plants are automatically dispatched down. The wind resources are on the board, and you can see what’s coming on and how much wind is in the system, and it’s become a resource like any other in the market.

I think the interesting things are how groups like the wind industry and others came to political compromises to negotiate these rule changes. We have a set of interviews talking about how the wind advocates needed to bring an electrical engineer with them to the meetings to learn how to speak differently and negotiate kind of what the different systems would look like.

One of the things, I think, from the policy perspective that is particularly interesting is that wind now within the MISO region is not being driven by renewable portfolio standards. Wind is treated like any other resource, and you have utilities like Xcel arguing that wind is the least cost resource and that’s what they’ll be building in the future.

Within the region, wind has become a resource that’s now treated like any other, and MISO’s working, actually, within their capacity markets to look at seasonal constructs both for wind and solar to think about what types of new planning tools they need to think about large scale wind and larger scale solar within the system. I think for all of us asking what next generation of tools will be necessary is interesting, too. I always joke that this is your RTO pickup line: “Come into my algorithm.” But this idea that these tools and rules are negotiated within these committees, agreed upon and passed by the board, approved by the FERC, and then implemented by the operators in this particular case, is really interesting. The question of these rules and how they matter and how they affect the value of technologies in practice I think is absolutely fascinating.

You’ve had an example now of PJM processes and CAISO processes; I’ve given you an example here of the MISO processes. When we’re thinking about how these play out in practice, I think it’s important to consider not only how it happens within one RTO, but across RTOs, and how in some ways each RTO has created its own logic, and how that works is also interesting.

**Speaker 4.**

I appreciate the opportunity to come before you all and talk. I actually really enjoyed putting together our observations this year about

governance. I reached out to a lot of the ISOs. Thanks for a lot of the comments your brought. I got comments from NYISO and MISO. I got a lot of less constructive comments from a lot of colleagues who do what I do on a daily basis, but some of them were constructive.

This first slide is just our corporate disclaimer; we're not trying to provide investment advice or looking for investment. I have a second disclaimer; these are my thoughts and my thoughts alone. I call it the self-preservation disclaimer because two of my colleagues who have a very good influence over my continued employment are here, and we also have a lot of ISOs here that we have many issues in front of.

My first hypothesis is really that governance has undergone significant change. I started in the governance process actually 36 years ago. I was a couple years out of college, and I joined the New York Power Authority, a state utility, and my boss gave me the Blue Book. It was a functional description of security constrained economic dispatch and billing policies. It was 125 pages. That was the tariff. Fast-forward, I looked at NYISO's tariff this morning, and it's 2462 pages.

I went to my first meeting sometime in March of 1980. I walked into a room. There were seven other white guys smoking cigars. I think it is not a stretch to say ISO governance has changed from two perspectives: back in that time frame, you had three types of power pools. They had unanimous consent. You had the rest of the world that just had vertically integrated utilities negotiating with their state utility commissions on moving power to customers at reasonable rates. I think there are good governance rules that exist. We have a democracy that looks for market-based solutions. It's an inclusive process. You educate. You have a lot of discussions. You identify issues. I hear a lot as I go from ISO to

ISO. I have the opportunity of currently focusing on MISO East. I spent a little bit of time out in CAISO maybe ten years ago.

The success of governance is really a function of stakeholders working together, as well as of the structure that we put together. As I said, a bad structure can succeed when you have stakeholders that are willing to negotiate good market-based solutions. You can have a perfect solution that fails, again because of stakeholders' inability to work together.

Governance exists at two levels: you have the governance stakeholder process among the stakeholders, but you also have the governance of the ISOs themselves. There's a little less transparency around that. How does the ISO board and management work together? How do the state PUCs and the federal commission influence that going forward?

Stakeholder governance varies across the ISOs. You have different committee structures, from none in California, to some other ISOs with very procedurally elaborate structures. We heard about the consensus issue building resolution process. You have footprints where you have three ISOs that are single states, and then you have very large diverse ISOs, like we have with MISO and PJM.

Retail access is another variable. Some have a lot of restructuring, some have none, and some are mixed. Some, as I said, evolve from tight power pools, and I take my hat off to those that came from nowhere and have moved up in the ranking to be just like those that had a lot of history. You have control area sizes as small as 30 thousand megawatts, and then you have large, diverse control area sizes of over 150 thousand megawatts. You have a one-state ISO that is not FERC jurisdictional.

And I'll take a leap of faith that people understand the difference between a 205 Federal Power Act filing versus a 206. Most of the ISOs have that ability, except for PJM and NYISO, and all this results in a very different process to enact change.

One of our hypotheses is that, similar to other companies, for profit companies, not for profit companies, the boards and senior management spend a fair amount of time talking about governance, because they're the primary custodians of governance. My personal opinion is that the ISOs, they may talk a lot about governance behind closed doors, but they have not been leaders in this, and this is one of the things that I think we need to look at in the future.

The stakeholder committee organizational charts vary. I went to each of the ISO websites, and all of the other ones besides PJM have very similar structures. Voting structure at the senior committee level varies significantly. Speaker 2 talked about the Market Surveillance Committee in CAISO, which isn't a committee in the sense of a governance process, other than it is a very good vehicle for stakeholders to be able to get up and have discussions with an excellent committee that they do have. As Speaker 2 said, there's no voting structure, so I put the rest of the ISOs in two basic camps of restricted membership and a very broad membership.

Two examples where you have advisory committees are ERCOT and MISO, where you have individuals that can be on that senior level committee providing advice to senior management and the board, but there are small numbers of people within the larger stakeholder community. The MISO advisory committee is an example. It's a great vehicle to communicate to the board. There are only three representatives of all the power marketers in MISO. They have

the ability to speak to the board at these advisory committee meetings. The rest of us need to be silent. There is sometimes a time at the end of the discussion where people from the floor can make comments as well, but it's a more restricted membership than we see here in both New England and NYISO.

When I first got into NEPOOL and ISO New England, I couldn't figure it out. ISO New England, that I understood, but then you have this parallel group called NEPOOL, and you have a single law firm who represents the interests of a very broad diverse community. In both NEPOOL and New York and, as you'll see, in PJM, everybody gets to a seat at the table; everybody gets to vote. Then they have very prescriptive voting structures in New England, with different sectors with the different voting percentages. You need 60%, for market issues, and 66% for other tariff or governance-type issues. In New York, you have a 38% threshold. In PJM, as Speaker 1 went into, you have 67%, a two thirds, sector-weighted majority. The interesting piece about PJM is that in its original tariff, they had five sectors, but you needed five PJM members to self-select to go into a sector for it to be populated. When PJM became an LLC, there were only four populated sectors, the last four listed on this list. Some smart people in the end use customer sector said, "Hey, wait a minute, I only have 25% of the vote. How about five of us go over to the electorate distributor sector. We just pumped up our voting power from 25 to 40%," and that's where we reside today. SPP also has a very restricted membership in terms of very structured subsectors who get to be on the committees.

Another issue that influences governance is the pace of change. Governance definitely influences the pace of change. Some of the initiatives that we've seen in our almost 20-year history have moved along very quickly. In six

months or less, there have been some significant changes, but then we have some other changes that have languished for more than 10 years. Here's an example: Some market participants in the 2004-2005 timeframe went to the three northeast ISOs and said, "We have a pretty plain vanilla FTR market." You got to bid and award an FTR position for an entire year, and then you had monthly reconfiguration auctions. Let's use New England as an example. The auction would occur in November. You would get a position for a calendar year. Any company taking that position would have to wait 10 months to reconfigure its position for, say, the month of September. People went to the ISOs and said, "Let's have these strip auctions; you can bid on any piece of the remaining either planning year or calendar year." In less than a year and a half, PJM went from an idea to implementation. The first discussion was around August of 2004. We had the members' committee in January 2005 voting changes of the specific market structure. You needed some IT changes on the PJM side, but in less than a year and a half, you had this implemented. New York and New England are still talking about it. Here it is 12 years later. There are different reasons in New England for this lag. There are some credit issues that have been yet to be worked out. In New York, the issues are more associated with IT and limited resources.

FERC, the ISOs and stakeholders have significant influence over the pace of change. You have veto power, just talking about the PJM structure in terms of the voting. If you have 40% of votes that reside in the electric distributor and end use customer sector, it's very easy to see how you can get the one third minority needed to stop changes from going forward.

FERC has open dockets on issues; I'm not going to specifically talk about any one of them, but there are open dockets where the stakeholders

and the ISOs see that and they say, "Well, why do we want to have discussions here, because the Commission obviously is going to come out with a decision at some time," so that things get put on the back burner and aren't discussed for a period of time.

In terms of enacting change, ISOs have limited budgets. I talked about the FTR progress, and you have somewhat of a beauty contest where, if you have a limited budget...I'll use the New York budget and priorities working group as an example. People had concerns with the way it was in the past, where you would bring forward a project, there would be discussions, the ISO would go off and makes decisions based on those discussions. We evolved. The ISO came up with an idea of, "OK, let's have a voting structure; let's have a ranking structure within that process," but at the end of the day, you still have limited budgets and limited staff to work on changes at the same time. My point here is that the goal is efficient market structures, not a rapid rate of change.

As we all know, the process is resource intensive. My original slide said it cost a lot of money to be involved in the ISOs. There can be 400 meetings per year. Sometimes you go to a meeting where there's 12-15 people in a room; sometimes you go to a meeting and there's over a hundred people in the room and another 50 or 75 people on the phone. That also is a challenge in trying to enact change. There's several levels to enacting change; you have the committee structure that we've talked a lot about, but several ISOs have the alternate dispute resolution process where you can go through a mediation process and/or an arbitration process. You have direct appeals to the board. Speaker 2 talked about how it happened in CAISO. In PJM you have a user group where, if you have a minority group of stakeholders that get voted down time after time, you can still bring it to the

board, because you can create this official user group and bring an issue to the board. NYISO similarly has an appeals process where you basically have oral arguments in front of the board where something goes forward, either it gets voted positively or it doesn't get voted positively, and you can still have a direct appeal to the board. Obviously, the Commission and the states do have the final say.

I just have a couple of comments on the various ISOs. ISO New England has 205 rights over their governing documents. In this ISO/NEPOOL structure, if the ISO and NEPOOL don't agree, the ISO is forced to file both suggestions to the commissions. They call it a jump ball process. Frankly, my experience over the last 12 years is that this has been working.

I get the opportunity or challenge of going to ISO meetings across many different venues, I keep looking at NEPOOL, and I scratch my head how it works, because it has been working consistently for the last 12 years. You go to a market committee meeting, and there are knock-down, drag-out fights. It seems like we're totally polarized. You get to the participant committee and it passes with 76% in favor.

New York and its stakeholders continually talk about shared governance process. That, too, has been working, despite the fact that NYISO is pulled in several directions. Having a one state ISO, you have many forms of government that are continually giving you advice if you will. Even in the New York Tariff, the state commission can and does attend board meetings. I talked about the appeals process in New York.

This first bullet on MISO is frankly from MISO's general counsel. MISO governance is both voluntary and advisory. That is true with a lot of them. Certainly it's voluntary. MISO has

205 rights. After almost 15 years of discussions on creating MISO and actual operation, stakeholders in the ISO said, there must be a more efficient way. They've been spending almost the last year coming up with positive changes to make the process more efficient. One of my observations here is the MISO board markets committee is a great venue. You have a two-hour time frame where you get to listen to board members, the ISO management, and the external market monitor debate issues, and at the end you're able to make comments. When I got into the MISO process, I made the mistake of asking a question, and one of the directors very politely said, "Young man," (that was a while ago), "You're able to make statements, but not ask questions here."

In PJM, they don't have 205 rights over their tariff, as I discussed earlier. One of the things that creates what you might call an issue of voting market power is the fact that you can self-select which sector you come into. A lot of it is very prescriptive, and this was created by stakeholders, not by PJM, but you have a venue. If you don't have assets in the footprint, you can't be in the generation owner's section. There isn't a public power sector, but what results is you have a number of entities that are industrial customers, public power, transmission owners, and generators that are in the "other supplier" sector. To be fair, you have a financial participant who is in the "end use customer" sector. Those are all allowable. A former employer of mine, we were once, even though the employer was a generation owner, we were once in the "end use customer" sector.

Another question that has been raised by many stakeholders is that coalitions have formed. That's great. But you have comments by people who are saying, "Well, you have one person when you get to a vote who now holds up an iPad that says 23 on it." So, is that a way of

skewing the vote, where you have a handful of people that wield a lot of voting power?

As I mentioned earlier, minority interests can be brought forward to a user group to bring an appeal to the board. In my first SPP meeting, or my one and only SPP meeting, I walked into the room; it was the high-level market operations policy committee. There were literally a hundred people in the room. You passed around a handheld mike and everyone introduced themselves. Ninety-three out of the hundred people represented utilities. So it's not a very diverse community.

Another significant challenge of SPP governance is that if you become a member and you want to leave, there's an exit fee. Now, for a company, say DC Energy, with no assets in the footprint, we sort of scratch our head and say, "What's that exit fee?" Well, it's based on your share of the outstanding debt. So, when we looked into it three years ago, it was 894 thousand dollars, and we decided not to join SPP as a member, but we can be a market participant.

The last point I have is what's universal in all the ISOs and a lot of the comments I got from other stakeholders is that we enjoy the access to the board because the board is very engaged in all the ISOs. We know they're the decision-makers. One thing we're asking the ISO boards to think about more is whether they should be a little bit more involved in the governance process to make improvements going forward. Thank you very much.

### **General discussion.**

**Question 1.** We've seen the stakeholder processes grow from relatively small to what they've become now. Is it time, and if so, what should be the forum, to look at best practices or improvements to more standardize the approach, if that's appropriate?

*Respondent 1:* I'll take a shot. The first part of your question is very easy. Yes, there are a lot of infirmities in the stakeholder process across the board. Best practices? You know, we can cherry pick. In each of the ISOs, there are some really good things that are happening. The problem is, as Speaker 2 laid out, how do you enact change? You know, people are not going to vote themselves less market power, less power in the voting process, but I go back to the first ten years with PJM, and I was amazed. There was a relatively small number of market participants and people were really voting for market-based solutions. In fact, I think besides the fact that we went from four to five sectors, I think I'm one of the problems there. I got up in front of the PJM members' committee and I commended the stakeholders and said, "I don't know how we do it, but we get to the right solution 90-something percent of the time," and I think that was the last time we gained consensus on issues.

*Respondent 2:* We've just done about 20 interviews with PJM, and they talk about how people vote the bottom line and how much more difficult that has become, in part because the issues aren't these big foundational issues, but issues where moving the bar this way or that way really does affect my financial position in the market. I just wonder, as the rules and the markets are more established, how then change and innovation can happen in a place where changing the rules is not making everyone win. We're shifting things around in different ways. I'd love your ideas on that as well.

*Respondent 1:* If I can add a couple thoughts. As I mentioned, PJM's been through this grand evolution, since 1927 if you want to go back that far, or 1997, and we've gone through a couple of deliberate changes. In our process, most recently in 2009-10 following Order 719 through what we called our GAST, Governance Assessment

Special Team process, there are a couple of things that have to happen. First of all, I think you have to have a little bit of a burning platform, because you're talking about a system with a lot of ballast in it. So, to go about changing a governance structure, how we make decisions, decisions that have very high dollar impact at times, you've got to have some real reason for making that change, and then have some guiding principle for getting to that. So the experience we had was, we've got this thing that makes people crazy, which is this balance of power. We realize we can't do anything about that; as the previous speaker just said, you got to have a vote to change the sector way to vote, and that's not likely, so what do we do? That's how they came up with this concept of, well, let's try to find solutions around which we can all gather. This consensus-based concept. We made that evolution, and we tried to get structured and improve the process, but at the end of the day, you know, we've always got to tweak it. So after we implemented those changes and we evolved our stakeholders and actually made the change and implemented it and evaluated how we were doing with the actual implementation, we instituted something we call the stakeholder process forum. We're trying to come up with names. The forum is a monthly informal gathering of whatever stakeholders want to come. It's typically on the order of 40 or 50 individual people across the spectrum of our stakeholders who participate. It's an unstructured, unagenda'd discussion of what's going right. I remember I did a lot of work with the Boy Scouts, and we used to help the kids understand this concept of evaluation, a very simple one; stop, start, and continue. What things are we doing that we should stop? What aren't we doing that we should start, and what things are we doing that we ought to continue? We'd do the same thing there. We look at how we're doing well with some things, and how we can expand and exploit that and so forth. So it's,

what are we doing within the rules that are practices that we can change easily? And then, what are things that we might want to consider making a change in the rules around? We do that on a monthly basis. We've met doing that since about 2011 or so. Yes, these are tweaks. To do anything more than that you have a reason and a little bit of burning platform.

*Respondent 3:* I think one question was, should we be looking at best practices? I think that's always good, and as to what forum to do that in, I kind of think the onus is on people that want to improve their own processes to sort of see what best practices are. Should we standardize? I don't think so. Speaker 4 raised some points about single states versus multi-states versus Texas, and I think there's another level that was being raised by Speaker 3 related to the political balance that's happened in some areas. They've reached a balance where they are comfortable that they are being represented appropriately, and to have a change mandated where there's a sort of a political balance, unless there's a real reason to mandate that change...I just don't think it's healthy. I do think there is sort of an organic reaction where, if there's really a problem, you're going to have the people really impacted raising their voices. Each area is going to sense when they've got a problem. I do think looking at best practices is always healthy. I would be very averse to sort of a mandated, crammed down, unified stakeholder process for the nation.

*Respondent 1:* One other comment to your question. My personal opinion is, Commission, please give PJM and New York 205 rights. I think they're the only two public utilities that don't have 205 rights over their own governing document. As I said earlier, I think in New England that has forced people to the table. My observation in PJM is less so, because they know they have veto rights. So, to make a

significant change that you ask about, it's not going to happen when stakeholders have 205 rights.

*Respondent 2:* One of the quotes I had from MISO talking about the stakeholder process was, "Well, I feel this had been very successful. Everyone is equally dissatisfied." I joke that this was like a good marriage. There's this idea that everyone is coming to the table, and how they're governed in practice is Robert's Rules. At the University of Minnesota, anyway, we don't train our electrical engineers in parliamentary procedure, but I have lots of documents from our interview with the MISO stakeholder process about how they have had to train engineers in how to run their meetings using Robert's Rules and parliamentary procedure. Anyone knows you can game the system.

Speaker 2, when you were talking about this "where all good ideas go to die" thing, what issues come up? What issues don't come up? Whose priorities are prioritized in the stakeholder process? I think it's really instructive. We've talked about the opportunity cost of participation when you have hundreds of meetings a year, and there are some groups that actually aren't able to participate very well, whether it's the consumer advocates (and now they're being paid for in PJM), or the environmental groups, and how they're working in California but not necessarily in some of the other ISOs. There are some groups that are more successfully part of the decision-making process in discussion and debate, but it's not a larger civil society discussion. This ties in to the point that I want to bring up, because being legitimate within this process and being able to participate and shape the discussions is something that's very difficult. Even within PJM, where you talked about holding at the vote and the sectors kind of coming together, who is able to participate and who has the resources to

participate? I just think it's an important societal consideration and discussion.

*Respondent 3:* One thing that's helped on some of the smaller entities is the trade associations or coalitions. I think we had ESPA on an early one, so that's a way we've seen smaller folks have a very large voice.

*Respondent 4:* Just a quick thought, ditto a lot of those comments, but one of the things that I just thought I'd mention that we haven't touched on is how information gets shared out of the stakeholder process to a larger body, and we've actually, in PJM, had a lot of discussion about at one point. Fortunately it's not a lot of discussion anymore right now, but it's worth thinking about the role that the fourth estate plays, that the trade media plays in all this as well. We deal with 960-some members. You saw the breakdown amongst the sectors. We don't get 960-some members participating in our stakeholder process. In fact, for example, the "other supplier" sector is huge, but it gets only a few more people participating in the stakeholder process than the other sectors. So, how do all those other people learn about what's happening and rule changes and so forth? We have trade media follow a lot of our processes and report out on that. Something we hadn't mentioned; I just thought it would be interesting to note.

**Question 2:** Speaker 3, I was trying to understand your graph about the monthly contribution from wind. Does MISO have negative bids, negative price bids?

*Respondent 1:* Yes. On the map you can see some of the purple areas where prices go negative in the LMPs.

**Question 3:** I have heard that the stakeholder process is "legislative in nature," and what I think people mean by that is that we're never

quite done. So there's never a time that you put those constituent documents in a box and wait for some constitutional-type amendment process to change them. As you started to discuss before the break, what that means is that you really need a professional class of stakeholders. I will tell you that by virtue of the fact that I'm here, I'm not, for example, at the PJM TEAC (Transmission Expansion Advisory Committee) meeting, and my company pays for me to go to those, but they don't pay for anyone else. I wonder if anybody has considered the possibility that the tariffs would become more constitutional in nature and less statutory, so that there were fewer issues on the table all the time.

*Respondent 1:* It's a good question. This morning I actually kind of thought the stakeholder process was about to break out when I heard discussion of the capacity market rule changes and so forth, and I think some of the discussion this morning led itself to your question, this question about, did we get the capacity market rules right? We've totally revamped them under capacity performance. We're still adjusting those new capacity performance rules. We've kind of got these grand concepts out there, but we still have a myriad of implementation aspects to them. So I guess I could look at your question in a couple of ways: one, is it possible to say we've got a static set of rules? Well, as long as we've got stakeholders who are participating, at least in the PJM space, they've all got the opportunity, the way that we're structured, both in terms of corporate governance and stakeholder process governance (which as I mentioned before are really kind of intertwined), they've all got the opportunity to bring something up. It could be anywhere from a minor market rule change to a pretty sweeping change. We had one stakeholder recently who offered what we called problem statements as initiating documents to look at the whole day ahead commitment process with the

behind the scenes ultimate objective of removing day ahead commitment from the day ahead market and putting it into some other construct. That's a major league change, right? So we got that issue; anybody can bring up an issue at any time.

Is it feasible to put the lock box on and then only deal with incremental changes? I'm not convinced it is, honestly, for a couple of reasons: one is, we've got that whole stakeholder participation thing. The other is, these are pretty stinking complex rules. Somebody this morning said, are we ever going to get them exactly right, to the point where we don't need to be worrying about making adjustments? Then we've also got the, oh boy what just happened kind of polar vortex, big changes to our capacity market issues. Something else happens that makes us realize that maybe we need to address a significant change to our market to address something we didn't think about properly before...

*Questioner:* I do know that that is the way it works, and I agree with you that that is how it happens, but I guess the question is, from a policy perspective, would it not be better to take some of that stuff, call it set in stone, and then let people find ways to mitigate the issues from those decisions through the markets, perhaps more markets with the ability to hedge against some of those risks might develop, but instead, there's a lot of activity that happens to change the rules all the time?

*Respondent 1:* Yeah, you're right. A couple of other thoughts. We had somebody address this this morning. We have markets. PJM is very invested in its markets, but a lot of people I hear say, "Well, a capacity market's not a pure market. It's a hybrid scheme here." We're not at a point where we've got, like, a pure commodities market and we can step back and

let the market forces work their way. As long as we've got stakeholders that have the ability to jump in and do that, I think we're stuck with that.

One other thought. Back when we did the governance assessment special team (or GAST for short), we kind of talked about this. We talked about, do we have the ability to put things in a box and then maybe hold things constant for a period of time, just, say, two years, five years, no major market changes to X market, whether it's an ancillary service market or the energy market or capacity, whatever, keep them the same and only allow incremental change? I guess the question becomes, who makes that decision about whether it's incremental change? What happens if you get the, "Oh my gosh, something just happened" moment? How do you reopen then? What happens if somebody truly has a better idea? I think there are pluses and minuses. In our space it requires our stakeholders to agree to that, too, right? It requires our stakeholders to come together and say, "No, we're not going to make any changes for X period of time." Our stakeholders have not shown a propensity to do that.

*Respondent 2:* I guess there are a couple of moving parts here. One may be that you had a market design structure that just had issues, and the issues are materializing, and they need to be fixed. That seems like it's got some sort of terminus, that eventually you get to some more stable situation, but then you have the change in the industry, and it's a pretty dramatic change, going to sort of a de-carbonization and some of the issues associated with zero-priced energy. What we're seeing as hot on our radar from an earlier discussion is distributed resources now moving toward the distribution grid, and having a potentially very different world of the interaction between the distribution and the transmission operator than we have had

historically. So this is a long way of saying that until technology stabilizes, I don't see it being feasible to lock in a design and say, "That's sticking there." I don't see any end to the change of technology in sight; the evolution, I mean, is going to continue to evolve. There are certain market principles that will apply, but with this very rapid rate of change, I don't see that we're in a position to lock down the markets and just let that change happen.

*Respondent 1:* Thanks. You just hit something that I intended to say and I missed, but low gas prices changed everything, right? We've got distributed resources on the horizon. We don't know what's going to happen in New York with REV, or other places with distributed resources, and how that's going to play out. I fully agree with what you're saying, Respondent 2, that things change, the industry changes, and probably the market rules need to be able to be adaptable to those changes.

*Respondent 3:* One other comment. I don't know why, but the markets have not evolved. When you think about it, we're 20 years into market restructuring, and we're out of our infancy, but I still think we're in our adolescence in terms of a mature market evolution. Just to reinforce what was said earlier, people continue to use "capacity market" as a phrase, and that's one of the reasons we're still evolving. When I look at agendas across all the eastern markets' committees, you see capacity-related issues. New England spends a ton of time, they have markets' committee meetings that go on and on and on only about capacity market issues.

*Respondent 4:* I just wanted to highlight that your question is one that was asked across almost all the interviews in all the RTOs. I mean, what you're highlighting is something that is pretty common in today's RTO's engaged stakeholders. One group that we didn't talk

about earlier were the public utility commissioners, because they're ability to participate. Usually each PUC has one representative, but they can only talk to one or two people at a time. So, kind of within the commissions, the ability to get information about RTOs and decision-making is oftentimes really narrowed down and funneled down, so everybody struggles with this process.

**Question 4:** I have a question, but I want to sort of expand our horizons here about the context of this question a little bit. I'm going to give you an example of the worst performance of the stakeholder process that I know of. It's actually something I observed, and I saw the body language to boot. This was when California came to the Federal Energy Regulatory Commission back in the '90s about their proposal for the CAISO power exchange market and all that sort of stuff. This had the unanimous support of the state legislature, the governor, and, officially, of the three IOUs. The members of the Commission, and we could tell from their body language, thought that maybe this wasn't such a great idea, but their actions and the kinds of things they said at the time reflected the thought that, when you're faced with unanimity from the participants in the market, what can you do? You have to go approve it. We know what happened. It exploded. The whole thing collapsed. It caused all kinds of other problems in ways that were entirely predictable and predicted. That struck me as the worst performance. Stakeholder processes with unanimity don't guarantee good outcomes in this process.

Second is a meeting that I attended now maybe a year and a half ago or something. This was a public session and the market monitor was listing off things that he had been reporting on about fixes and pricing in the markets and so forth that he thought were extremely important,

and everybody else thought were extremely important, and he had been saying the same things in his formal reports for years and years and nobody was doing anything about this kind of a process.

Then we'll fast forward to this morning. We heard this morning in the panel, and I would characterize, the message as, the sky is falling, OK? That we have market designs which are completely broken. They're not working and we have to fix them. Then I hear this afternoon about the stakeholder process, which has got a few little minor problems around the edges, but seems to be working pretty well, OK? What is the disconnect here, and what is the solution?

Now, the only thing I can think of is that we've got to get FERC to do its job better, as I have said before. The stakeholder processes that you are describing are not capable of producing proposals of the kinds of things that we need to do that are needed to deal with the sky is falling problem that we're talking about today. The only one that has the legal authority and potentially the capacity to do it (I mean, the Market Surveillance Committee in California ISO, or the market monitor, I would say they have the intellectual understanding and the principles and all that kind of thing, but they just don't have any authority) in the end is the Federal Energy Regulatory Commission. Why isn't the message that comes out of this discussion this afternoon that we need to fix FERC more than we need to fix the stakeholder process?

**Respondent 1:** This morning's panel, I think, was two ends of the spectrum. I think a lot of what's happening in the energy market is working. What we hear continually from people who have invested frankly billions of dollars in infrastructure to keep the lights on is that their units are not getting paid. So, you heard from

one end two large generators and you heard the consumer side, but there's a whole middle ground where there's a lot about the markets that are working. That sort of tempers my answer to your question. I think I was trying to be strong enough to say that there are a lot of changes that have to come in the stakeholder process, so I think it's a balance of how you painted this morning's panel as well as this afternoon, because I think change needs to be done. When I bring this issue of 205 rights to PJM and ISO, they say, "Don't you know what you're asking for?" I said, "Well, look at it from our perspective. We're always in the minority." So, from my perspective, there are a lot of things that need to be changed in the stakeholder process, as well as some of the market issues that need to evolve.

*Respondent 2:* I think there's an issue of micro and macro. Based on my experience in the stakeholder process, addressing the micro issues is kind of what they do. There's a little tweak, there's a little change, there's fine-tuning, there's this one new thing to do. I think the stakeholder process is incapable of a macro vision, the standing back, and if there is something on the horizon five, seven, ten years out, it's incapable of reaching a critical mass of consensus that that really is the future that's coming. Without the ability to have consensus on the future that lies ahead, no action is taken on the macro state; it's very micro. How do you convince the right people that the sky is going to fall, and as a result, from experience, they don't believe it until it actually falls? It took that crisis to get a macro change in how we were doing things. This is a very difficult question when there's not almost unanimity about the future that's coming--to convince the process that can make changes that that is the future and have them act. Our little stakeholder process isn't going to do the macro from my view.

*Respondent 3:* I think there's also a lack of consensus on what the future is. You have a lot of kind of embedded business models now, and the stakeholder process does a really good job of helping to make sure they don't have to change. One of the pieces I only appreciated kind of halfway through our interviews with people was how the FERC was viewed by the RTOs. Some of the best quotes we had were like, "FERC is a wild card." Most of the RTOs wanted to make sure they sent an issue up to FERC that was already pretty solid, because having lawyers who were paid 450 dollars an hour who may give you a negotiated settlement that's not technologically feasible...I mean, this is the type of language used when things are going up to the FERC. So this idea that within the RTO process they want to manage it in a way to kind of maintain their own political legitimacy I think was really interesting, but I do think there's also this feeling that, because the system is changing because of the new technologies that are coming on today, no one knows what the future's going to look like. Some futures favor certain business models and completely don't favor other legacy actors within the system. I think that's a tension that you're seeing, the inability to address some of these larger issues.

*Respondent 4:* I'll speak to it strictly from the PJM space. These are somewhat dispersed thoughts, and I apologize for not making them more cogent, but I think there are some threads here that need to get pulled. One of them is the question we were first asked about why can't we put a box around these rules and keep them the way they are for some period of time? It doesn't account for market-forced changes or significant events that we need to deal with. As Respondent 3 suggested, we've got stakeholders who are invested in a market rule set the way it is. They've built their business models around it. Within our world, we've got this corporate governance and stakeholder governance thing.

It's all combined up. We've got people who have a vested interest in keeping things the way they are with the ability to veto any big changes that come out. We've also got this 205/206 dichotomy, but one of the things that I'll just point out as a way that we can, on occasion, rise above that, and we've talked very briefly about it so far, is this enhanced liaison committee concept that we used for the capacity performance changes. They're arguably pretty large changes to PJM. Maybe that's the level of change you're talking about, or maybe it's not large enough, I'm not sure.

*Questioner:* I'm happy to talk about it. It's a great example of tunnel vision and not looking at the larger problem. So, you have the capacity performance mechanism, which could produce, in shortage conditions, five thousand dollar penalties for generators that are not showing up and 50 dollar market clearing prices. I mean, it's not connected to the demand side. It's just passing money back and forth amongst generators, and it doesn't reflect how markets would actually work in that situation. It's a good example of the problem.

*Respondent 4:* I hear you, but that is still an arguably large change to PJM's rule sets. When the stakeholders talked about, how do we do something when we can't come to agreement that will influence the board and its making a change, they came up with three triggers for implementing this enhanced liaison committee process. One was they'd take something through the stakeholder process and it failed, but yet they'd recognize that the board was going to do something, so they'd vote to implement this thing. The second was they could come up with a new issue at its beginning and say, "Well, this is too big, we're never going to come to consensus on it, so let's start this process." The third was that the board could trigger it. So in the capacity performance situation, the board

actually triggered it. It was the only time we've used it, and a lot of stakeholders actually got pretty upset because the board triggered it rather than the stakeholders triggering it, but there is that mechanism for the board to trigger something around an issue that's large and that is not expected to get consensus among the stakeholders.

OK, there are a couple of threads. Let me throw a different one out there. I've mentioned several times that our stakeholder process in its current form is really aimed at stakeholders coming to consensus on a change. Is that realistic? Well, it works in a lot of these minor tweaks and minor changes to the market rules. Here's the question I'll throw out. and perhaps I'm answering it. Is a consensus-based model a model that's going to produce the best design? Is that another way of framing your question? We've got something here that's aimed at trying to come to consensus. If we're doing it right, it's trying to come up with the best solution that meets all the needs and accommodates everybody's positions. If we're doing it wrong, it's the lowest common denominator. It's likely going to be somewhere in that space, right?

So, is that a model that you can count on to produce the best market design? Maybe or maybe not, but given our governance, the way we're structured, and unless it changes, I think we're set up for that, given PJM's corporate governance with our operating agreement that I mentioned before.

One last thing I'd mention along this line is that we've recently done our stakeholder survey. We do it every couple of years, and we get a lot of great feedback about how we're doing business, and how we're serving all of our stakeholders, whether they're members or not members. Interestingly enough, our stakeholders gave us very good response, and we're going to be

rolling this out over the next couple of months so you'll see more about it, but very high marks on the stakeholder process in general. For those people who gave a negative response to any one of our questions, they're asked to provide some verbatim comments back. It's interesting to review those, that wealth of knowledge that comes out in the verbatims. We get two ends of the spectrum on almost every one of those questions. We get, on one side, "PJM is too biased, they've got their thumb on the scale, they're having too much influence on whatever the market design issue is at question." On the other side is, "PJM should be only doing what's right for the market, the best market design." So we're stuck in that space. Being a member-governed organization, we're stuck in that space, and we have to try to navigate it, and perhaps that's the reason you're asking the question.

*Respondent 5:* From my perspective, the folks who run the RTOs and the markets are at times perhaps a bit reluctant to be completely forthright with the Commission in terms of the real big challenges they see, because they're regulated by the Commission, and to the extent that they can be more uniform, along with market participants, in expressing the state of play, that might be more effective in getting the message across.

*Question 5:* The reason the stakeholder process is muddled is because the mission of the RTO itself is really kind of muddled, if you think about it. I'll give an example. We have new board members come on. They've been appointed to a board of an RTO, which is a great gig, by the way, if you can get it. They get appointed to the board, and they sit down, and the first thing is you're instructing the new board members on what they're supposed to do, and you say, "Well, FERC tells you run it like a business." They say, "Well, we're business people, we get that. You got it. We'll run it like

a business." Then you also tell them, "Another part of the mission is to be responsive to stakeholders." They say, "We're business people, we've got customers, we got that, we understand that." So they say, "Ready to go?" And you say, "Wait, wait, wait. There's another mission here. You have to make all these sort of quasi regulatory decisions. You've got to decide issues like cost allocation." And they're going, "What? We have to do that?"

And there are all the various balancing equity issues that normally the regulator does, but you sit the board down and you say, "No, you've got to come up with them and propose them to FERC," and they get very confused. They say, "We're supposed to run it like a business, we're supposed to be responsive, but now I've got to sort of make all these decisions that I thought the regulator makes." Then, if they're not muddled enough in that, then you sit them down and you say, "You know what? There's also all this pressure on you. You need to promote demand response. You need to promote renewables. You need to promote energy storage." They say, "Wait a minute, wait a minute. I thought that was a public interest board down the street? I didn't know I signed up for that one." But they've got all these sort of competing missions, and you sit them down, and in fairness to the board members, they're confused when they first come on as to exactly what are their responsibilities.

So I'd like to just pose that, that maybe the bigger problem is we've got these very muddled missions. I think we're all trying to do our best with them, but there's a lot of competition between being responsive to your stakeholders, being independent, making regulatory decisions, promoting various technologies, and running the place like a business. I'd like to hear the groups' responses to the question, is that too muddled,

and therefore the stakeholder process is muddled as a result?

*Respondent 1:* That's like any utility, right? I mean, that's what an electric utility does. Yes. If you think about the utilities in a traditionally-regulated state, they have to also deal with state policy. They have to also respond to regulation. They have to fulfill the obligations to their shareholders. They have to make sure the lights stay on. I mean, those tensions exist within a utility. What makes this challenging now is now you have over 15 states, and you all need to somehow come to consensus across very different political territories with very different priorities.

*Questioner:* A utility certainly tries to balance, but I don't think it has a mission to balance the competing views of stakeholders.

*Respondent 1:* Fair enough.

*Questioner:* It wants to do that, certainly, but I don't think it has that as a mission to propose to FERC a balanced solution. That, I think, is a key difference.

*Respondent 2:* I think one of the key differences is those issues that you're talking about are ones the board and senior management have to deal with. As stakeholders, we see a very clear mission: reliability, efficient markets. These other issues, they're part of the discussion, but in terms of what I believe the ISO mission is, it is to keep the lights on and have just and reasonable rates. But you're right, these other externalities, if you will, provide you all with very challenging discussions, but I don't think that leaks over too much. Yes, stakeholders press the ISO for their projects, but in terms of the missions, I've never looked at the ISO's mission as being muddled.

*Respondent 3:* In the California structure, the board is appointed by the governor, and there really is a sense of understanding the governor's broader objectives, and there really is a desire to see, within a framework, how they can facilitate that, so it becomes part of their agenda or objectives. That doesn't necessarily mean there's anything wrong with that. For example, one of the reasons we're looking to expand the footprint of our ISO is to help achieve 50% renewable targets by getting a broader footprint, getting access to more renewables, getting access to more flexible capability to help balance the intermittency. To me, that's sort of healthy. The objective was renewable facilitation and they are looking for healthy ways, in that example, on how to accommodate that.

Now, on the flip side, the one non-unanimous vote that we had had to do with the elimination of a subsidy that was going to wind generators. There was a baked-in subsidy, and personally I did not think was appropriate for an ISO to bake in a subsidy for technology, and the big debate on the board at that stage was whether they should cut off the subsidy immediately, or whether they should phase it out, but at least the board was aligned with the idea that the ISO should not be providing subsidies to technologies. There is an agenda. There is this other force that is trying to achieve higher objectives. If those are good objectives, great. If they were bad objectives, I might feel differently.

*Questioner:* I'll just comment, on that last example about subsidies, that's sort of a quasi-regulatory decision that we're calling on a board to make at the same time we're giving them all these other responsibilities, but that really is a regulatory issue, I would argue. That's an example, I think, of this kind of muddled mission.

*Respondent 3:* I think it's sort of a case of conflicting objectives. If your objective is to provide a non-discriminatory, efficient marketplace, what the heck are you doing providing a subsidy to a certain class? I'd say the board kind of realized that, and that's why they were eliminating it, but earlier on, it was put in place. There are muddles and there are some mixed signals over, really, what the board should be doing.

*Respondent 1:* I think this question of larger FERC priorities, and what the priorities of the commissioners are, and how that trickles down to the RTO, I think is absolutely fascinating. I hadn't appreciated before how demand response picked up, really, in PJM, and for a lot of the states (most of the MISO states, for example) third party demand response remains illegal. How these FERC orders get picked up and how they become implemented I think is absolutely fascinating.

Earlier, one of the speakers talked about reliability, which really is the holy grail function. My colleague Natalie Nelson-Marsh is a communications scholar, so when she analyzes all of the RTO documents, that one's held up first. That's the creation myth, right? Markets are on top of that, but they're negotiated with this construct of reliability first. Only later on, with Order 1000 and others, this idea of policy goals comes in. And if anyone can tell me who said this, I'll buy you a beer during the free cocktail hour [LAUGHTER]: "MISO is not a policy-maker, it is a policy-taker." But there is this idea that the RTOs are there to facilitate states in their regulatory and policy obligations and, like I said, the free beer's on me.

With respect to these multiple objectives, I'd like to add just that larger policy one as well as the states and the members, particularly in the

regulated states, how that plays out in the RTOs I think is interesting.

*Question 6:* I have a comment and a question. The comment is sort of picking up on the remark about how FERC directed RTOs to be responsive, so why do all these stakeholder processes exist? At some level FERC was worried, years ago, about RTO withdrawals, and members were concerned that they were disenfranchised, they had no way to express themselves to RTO management and boards, so they wanted some way, some structure, to express themselves, and that seemed perfectly reasonable, so FERC directed responsiveness. But FERC actually didn't necessarily want RTOs to follow the views of stakeholders. FERC wanted them to listen, but very much in the way that FERC under the APA has to listen to comments and read comments. If you get a meritless comment at FERC, you ignore it. We thought the same should be true in the stakeholder process; if you get a meritless views in the stakeholder process, an RTO should feel free to ignore it. FERC also thought an RTO stakeholder process would produce some kind of a record to support a filing, and it would ventilate issues, so it was convenient for the Commission to have that sort of a pre-record developed, and also it would give market participants an opportunity to identify rule changes. The RTO management and market monitor wouldn't necessarily be the source of all wisdom on what rule changes would be needed, so market participants should be able to flag those. But FERC didn't expect that wisdom would necessarily occur from the stakeholder process. It didn't expect consensus to emerge. It didn't want RTOs paralyzed by the lack of consensus. It didn't want RTOs to hide behind a stakeholder process. There are some examples of that, when an RTO has taken some obviously really controversial issue and said, "I've given it to the stakeholders to work on," as if there was

any hope that that would produce fruit [LAUGHTER].

FERC didn't want RTOs adopting the views of stakeholders, not even necessarily where consensus emerged, and there were some cases years ago where RTOs were making filings that FERC totally supported, but the filing essentially said, "This is what the stakeholders want." FERC thought, "Look, an RTO has a burden, just like a utility, in showing why their filing actually meets FERC legal standards, and just saying, 'The stakeholders like this. Please approve it,' really doesn't meet the mark." It took a few times to send that signal. I think RTOs are better now at making their case.

My question really goes to, what happens after the stakeholder process? A stakeholder process doesn't necessarily produce wisdom or consensus. Say the RTO adopts some view, maybe one of the stakeholder views. It makes a filing. But sometimes RTOs are not as fully committed to market integrity as we'd like, and they might make a filing that reflects that. FERC's level of confidence waxes and wanes from one RTO to the next over time, and you really can tell if you read a lot of these orders, and you can tell by the verb that's used, or the adjective that's used, or the tone--but it's not obvious. People don't really read these orders a lot.

When FERC has lost confidence in RTO, is there a way to manifest that? Is it really just through adjectives and adverbs and tone? I struggle with the question, what is another way to send that signal? I mean, RTO boards are not the most accessible universes in the world, and there's the Commission, that I don't think can actually meet with an RTO board, right? Because there would always be something pending. So, my question is really this: is there some other way, when an RTO is losing the

confidence of the Commission to let the RTO board sort of know early on that, "Hey, we're on thin ice at FERC and that's not great," and to send that signal both to the RTO board and to management, or are we really just left with adjectives, adverbs, and a string of losses as really being the way to send that signal?

*Respondent 1:* Phew. I'll focus on the positive. I think the RTOs have done a better job of making their boards accessible over the last few years. I think it started, probably, in 2010, maybe 2011, where our chairman at the time, John Wellingshoff, had to cancel his attendance at the IRC (the ISO/RTI Council) meeting in Dallas, so I ended up flying down there and then coming back and saying to all my colleagues, "We need to be at this IRC meeting annually, because it's the most concentrated ability to interact with the boards of all the RTOs," and I think, thanks to PJM meeting in D.C. last year, that was done. I guess, just like I would urge to all regulators, keeping your independence is absolutely the key. You're going to have to make tough decisions, and you're going to make some people mad, probably, with every decision, but if you can keep that independence, the Commission has to back you up, but that should help alleviate some of the times when you can tell an RTO is torn as to which way it should go in terms of its filing, because of the negative reaction it's going to get from one quarter or another. I would hope that enhancing those communications between the state commissions and boards of RTOs can only pay big benefits.

*Questioner:* I totally agree with you on the IRC meetings; they were very useful ways to have that kind of discussion--how are we doing, what do you think we should be doing more or less? Those were really productive.

*Question 7:* My question goes to kind of stepping back a bit and looking at the cost

benefit of the stakeholder process that's evolved today. I'm wondering if there have been any reviews of the cost of running these very extensive stakeholder processes, cost to the ISO as well as cost to customers and market participants. Is there a model that can be looked at where there's more independence? Because obviously the ISOs were set up for independence, but are there examples where the process is run more like a utility or pipeline company, where there's input, but then the decisions are made more independently, or you go through the FERC process, rather than the extensive stakeholder processes. So I'm just wondering if there's been cost-benefit done to those.

*Respondent 1:* As I mentioned earlier, MISO's in the process of finalizing looking at just that. How many committees do we have? How many committees do we need?

*Respondent 2:* I've been with MISO for 15 years and I've been very involved with our stakeholder process. We did an informal cost-benefit analysis, very informal, we just raised some questions for discussion with stakeholders. We had evolved to where, in 2014, we hosted over 750 individual stakeholder meetings. The committee structure was loaded with subcommittees, work groups, task forces, and in theory those smaller committees were going to be formed, complete a task, and retire. In reality, they just kept growing, expanding. We had over 40-some individual charter committees. Our staff hypothesis was that just with the care and feeding at the RTO to support that many meetings there was an issue. There's not a separate staff of folks that really are supporting that effort, right? It's the same people that are administering the markets, running settlements, executing credit policies, running controls.

Some of the symptoms that we saw that were impacting the quality from the stakeholders' perspectives was just preparing and posting meeting materials for that many meetings. It was getting to the point where the staff just couldn't keep up. So, the hypothesis from staff that we eventually took to stakeholders was that the stakeholders and staff were working just to support this behemoth that had been created over time, and we were finding work to do and we really weren't spending time on key policy questions--impacts that are five, seven years down the line. So we engaged stakeholders about this time last year and said, "We really need to rethink this." We transformed the entire structure. The transformation is underway right now. We've got a commitment from both staff and stakeholders that we're going to spend a lot more time focused on key policy questions.

So it wasn't a formal cost-benefit analysis, but we sat down and had a conversation and said, "This doesn't feel like it's making much sense." Stakeholders initially were resistant to it, on the grounds that, "This is our process." But after we thought it through and had some discussions, there was a pretty wide agreement that the benefit wasn't quite what we hoped it was, so we decided to make some changes.

*Respondent 3:* If you don't mind, I'd like to offer a couple thoughts. That whole GAST (Governance Assessment Special Team) thing looked at a lot of different issues, and this was one of them. We looked at, do you do a cost-benefit, or do you develop some sort of prioritization scheme to say, "Hey, these are the issues that everybody thinks we ought to take on first, second, third, and push these other issues off until later." We got into it enough to recognize that we couldn't agree on a prioritization scheme, because everybody wanted their issue to be addressed first, right?

When we started looking at all the costs that Respondent 2 just mentioned, for example, staff support...and if you look outside of staff, and you look at individual companies, what cost is it to them to participate in all these stakeholder meetings? It's a lot. Recognize that. But you have to also be able to quantify the benefit, right? And is it cost on a per member basis? Is it cost to an individual member and then benefit to that member? So everybody's got their own cost-benefit ratio for it. How do you measure it? I think there are too many ways to do that to make that a useful metric, honestly.

**Question 8:** Let me start with an observation. We've had some notable failures of electricity markets outside the United States because of a failure of governance structures. For example, the England-Wales power pool had flaws. It also had some good points, but it had its flaws. But as I understand it, the governance structure almost required unanimous consent to make market changes, and there were some serious flaws that eventually led to its ugly demise, and then we ended up with new electricity trading arrangements, and now we've got some other things that are going on. Capacity markets have now taken hold in the U.K., and so forth.

Then there's New Zealand. New Zealand basically had a self-governing electricity market structure. There was no regulator. It requires unanimous consent. Again, there were some issues in that electricity market, and eventually that governance structure imploded, because there was an impasse; people couldn't come to an agreement, and government eventually stepped in and created a regulator to come in and kind of enforce some of these issues.

That's just some food for thought there, but I guess where I'm going on this is I've got really three big questions in my head thinking about those lessons from other places. The first one is,

are we in danger of facing those same problems here in the United States with the governance process and some of the complaints that we're hearing about the cumbersome nature of the governance process that we've seen in other places? The second question is, has the governance structure of RTOs gotten to the point where it's almost like a quasi-regulatory function in many ways, and has this just become another avenue for rent-seeking behavior on the part of not only politicians but also market participants, where there's a sense of capture through lobbying in much the same way that regulators and legislators are captured? And then the third question is, in order to make changes, given that we need at least a super-majority in the context of PJM, we often have to make compromises, which often lead to other problems, or have in the past led to other market design problems that have required further stakeholder processes to cure? Given that, are we comfortable with settling for second or third best solutions to attack the main problem, only to come back at a later date and address the problem we just created because of the compromise, and creating an additional turn in the stakeholder process?

**Respondent 1:** I'll just unpack a little bit of that. So, this question that we were talking about earlier about whether it is possible through a stakeholder process, one that requires consensus or a two-thirds sector-weighted vote at PJM, to actually come up with good market design without watering it down and having unintended consequences...we're stuck with that right now. I'm approached often by stakeholders who say, "Why don't you guys just make a filing to remove schedule one of the energy market rules from the Operating Agreement, so that you effectively have 205 authority over all of your rules?" It's a complicated question. A way to put that in perspective is that in PJM, the OI (Office of the Interconnection), under the guidance of

the board of managers, is considered by FERC to be the regulated utility, and I've had some people, both inside and outside PJM, look at that and say, "What other public utility has to ask its stakeholders, whether they're customers or shareholders, for permission to make a 205 filing?" New York ISO, I think, has some of that, and we have that. I'm not aware of any others. There might be; I'm just not aware of others. So, once we're in that paradigm, we're kind of forced into finding either some level of consensus on principles and then working out the details, or we have to get into a position where we can jump over the 206 bar and prove that whatever we have in place currently is not just and reasonable. Either a mistake was made or circumstances have changed. So we've got to get over that bar to meet FERC's legal requirements to make a change. We're in that situation. It requires some intestinal fortitude on our board's part to go against stakeholder will, to stand up and say, "No, this is the right market design," but I think we probably need to resolve that 205/206 issue. I don't think I address all of the parts of your question.

*Respondent 2:* All I have in mind is Arrow's Impossibility Theorem when I hear that. You mentioned it, you almost need a benevolent dictator or something along those lines.

*Question 9:* There have been two scenarios suggested today that are kind of troubling. One the one hand, we had a scenario painted that there's an iceberg ahead; why aren't you turning the ship? And who's responsibility is it to make sure that ship gets turned before we hit the iceberg? And I kind of said, "We can't see icebergs, so we need someone to see it and someone to act to it." Another sort of macro concern is, what happens if the board decides there's money for someone by hitting the iceberg and intentionally steers the ship into it?

What expression did you use for that? A "rent-seeking behavior within the board?"

Those are very, very serious concerns. I have to stand back and say there is a sort of overall governance at FERC, and ultimately, I'll say, the buck stops there, because I don't see either of those being addressed or preventable completely in the governance structures I see in the systems today. So I'm going to lean back on the important role the Commission plays, the importance of the integrity of the Commission, and if there are concerns that we do not have a proper structure to maintain the integrity of the Commission, then that's a federal legislative type of issue. I'm not there, but if people are concerned, then that only becomes a legislative solution to make sure that integrity remains.

*Respondent 1:* To answer your first question, I don't think the sky is falling. I don't think there's anything that points, even in the future, to a collapse, if you will. I mean, PJM went through a period where unanimous consent was the rule, and somehow you got it (albeit from less diverse stakeholders, back pre ISO). The term "benevolent dictator" came up earlier, but I don't look at the ISOs that have the 205 rights over the governing documents in that light. We've gone to each of the markets that have the 205 rights, and we've gotten things done. What I tried to relay in talking about the ISO New England case is that I think the 205 rights get everybody to the table to negotiate, whereas, when you have veto power, that option just doesn't exist. I often marvel over how in New York they don't have 205 rights over the tariff, but somehow stakeholders and the ISO are moving somewhat in the same direction, albeit the pace is sometimes skewed, but I think it's working, so I don't see the sky falling in any scenario that I'm looking at.

*Respondent 2:* I would have to agree with that. We've done about 60 interviews with people across three RTOs, and I go down to Texas at the Austin Electricity Conference, and I appreciate the alarmist's language, it's fun, but that doesn't seem to be reflected in the voices or opinions of the people we've talked to. While people are frustrated with the process, like how the previous questioner mentioned how hard it was to be part of it and how time intensive it was, most people also feel that the RTOs are very responsive to their needs. They can call up different people when they need information, and they're participating in the processes quite actively. So I appreciated, from the people we've talked to anyway, that RTOs, while imperfect, are organizations that they're working with and actively engaged in.

*Respondent 3:* I get the frustration. I do. Look at the number of issues that we deal with in the PJM stakeholder process, and I get the frustration that people have that it takes a long time, and that it takes a lot of investment. I guess one of the questions I ask in return is, well, should it be free? Should this process be free? Shouldn't it cost something to get involved in this process? I mean, it's a big important thing. It should take some level of investment to be involved in it.

I just want to also echo what I mentioned before, that you need a burning platform, I think, to change something with this much ballast in it, and I don't hear that right now. Other than the frustration that I hear about the 205/206 issue, at least in the PJM space, I'm not hearing that there's a burning platform out there right now. If we look at the numbers of issues that we deal with and the numbers that we actually do come to some level at consensus on, it's surprising. I looked at one that we put through last fall, the energy market offer cap. True confession time, I never thought we were going to get consensus

on a solution there. We worked really hard in a surprisingly short period of time, and we got almost unanimity on a change to the energy market offer cap, which we had tried to do a year before and failed miserably. It can work.

*Respondent 1:* With respect to that case, I polled some of those who I was surprised voted for it, and they said they were sure the Commission was going to come down with an order in that regard, or something leading us down the path, so they wanted to get out in front.

*Respondent 2:* They also knew that PJM was telegraphing that this was the 206 filing they were going to make if they didn't come to consensus.

**Question 10:** Let me come back to the question of cost-benefit analyses and ultimately rate impact. How and where in the process specifically are those matters dealt with, through the process all the way up, leaving aside FERC for the minute, because I think we've gone through that already, but where in the process that we saw on the sheets you showed and the internal processes of the stakeholder process are those matters considered?

*Respondent 1:* Great question. We talked earlier a little bit about cost-benefits, and the way I answered that question was not considering the impact on the ultimate rate payer. I acknowledge that up front. I think the question overall of cost-benefit is one where there are so many different costs to so many different participants, not only the ultimate rate payers but all the participating companies and benefits, also, to the rate payer, as well as all the different participants, so I think it's a different question to answer. So far, at least within PJM's space, we have not come up with a way of doing that yet.

I would add something that we haven't talked about yet. In the PJM space, the offices of the consumer advocate are actually members of PJM, ex officio voting members technically, which means that they get to participate, and they actually get to vote in PJM space. We're fortunate to have them participating. We're also fortunate that they have, through a series of circumstances, been able to set up an organization to get themselves better organized to participate. As most of you probably know, they've been successful in working with our stakeholders to come up with a tariff change to provide a funding source so that they will continue to be an integral part of our stakeholder process. So, while we don't have a cost-benefit analysis that accommodates what you're suggesting, I think that we have had and we are improving the ability for the ultimate rate payer to be represented in our processes. I just wanted to offer that.

*Respondent 2:* And there was some discussion in New York about that very issue, so what NYISO created a position within the organization that when they do proposals, analyzes the consumer impact on that very issue. The former consumer protection board employee is now an ISO employee, and his sole job is to look at these issues that are being brought forth, and what is the specific impact on the consumer.

*Respondent 1:* That's something that we learned from New York ISO, and we're actually looking to see if there's a way we can do that going forward.

*Respondent 3:* How does New Jersey participate?

*Questioner:* The commission participates through the process, obviously. However, from state regulators' perspectives, there is a perception that the ultimate rate impact is not

always a matter that is internalized through the stakeholder process, and that's why I asked the question, because it's something that state regulators raise routinely in different forums, both with the RTOs and with FERC, because we're the ones that ultimately get the phone call when the rates get put into effect.

*Respondent 4:* We tried for a while to quantify cost and benefits--and that catalogue that we bring out now and then, it was difficult, so we rely on the sagacity of our oligarchy now to determine [LAUGHTER]...but in seriousness, the idea of expanding to multiple states got significant political attention, and there was actually a bill, SP350, that actually mandated the ISO to perform some economic analysis of benefits to the California economy, impacts on the environment, and one or two other issues. They've been legislatively mandated to prepare some reports that the legislature will then use in some of its decision-making on whether or how to support the expansion beyond California's borders. So we do have that. They've been tasked explicitly in this case to look at it.

*Question 11:* I'd just like to add some observations on the 205/206 process. When I first came to the Commission, we proceeded under a rough standard of, if we can identify a market design that is more efficient and passes the cost-benefit test, that's enough for a 206 finding. The courts went along with that, and some of these restructurings, as some of you know, were fairly radical, and they bought almost all of it, hook, line, and sinker.

Over time, the 206 threshold has been somehow or another redefined, so just proposing something better and more efficient is not enough. There is some much higher threshold that you have to go through in order to pass a 206 test.

On the GAST side, we used to routinely set everything for hearing under both section 4 and section 5, and we would make a decision under section 4 and section 5 routinely and you really couldn't tell what was the section 4 and what was the section 5 part of the finding, but now there seems to be a much bigger threshold. So, consequently, just identifying a more efficient design is no longer enough, and that creates a bigger problem in getting to a 206 finding, so we'd sort of love to find 205 filings.

We like 205 filings instead of 206 filings, but the threshold has evolved, and I'm not sure exactly what event triggered this, to being a much higher threshold to do a 206 filing.

**Question 12:** I was going to ask a question about the actual results of MISO's reforms. I was just wondering what the net effect of all the effort was and whether it was even worth it.

**Respondent ITODD:** The MISO Transmission Owners' Agreement specifies the existence of just a few stakeholder groups; one is the Advisory Committee. Another one is the Planning Subcommittee. The structure of the stakeholder governance at MISO below those two is voluntary, charted in some respect, but it's not required to be there. That subcommittee level reports to the Advisory Committee, that required committee, and prior to our change, there were three subcommittees reporting to the Advisory Committee. After the change, now there's four, so we actually grew by one at that level. We had discussions with stakeholders. One of those subcommittees is a reliability committee, ones a market –

**Questioner:** I think I rest my case.

**Respondent 1:** Yeah. So, we actually grew by one committee, but we eliminated a lot of lower

level committees. We probably eliminated eight or ten work groups, but there's still 25 or so.

**Respondent 2:** I think they're moving to a more efficient solution of fewer meetings and putting groups together. So just because we increased by one at the top level, if you eliminate 20 or 30 at the bottom several levels, it helps stakeholders, it helps hold down costs, so I think it was an improvement overall.

### **Session Three.**

#### **Uneconomic Dispatch?: Frontier Challenges in Dispatch and Pricing**

*The changing structure of dispatch to incorporate the challenges of electricity markets presents opportunities for reforms in operations and pricing. New work from the European experience points to dispatch problems from the constant cycling of flexible fossil units. Wear and tear, a cost that is familiar for regulation assets, now becomes a possibly material problem for load-following units working on a different time scale. The impact can include accelerated requirements for maintenance. Yet dispatch models do not account for these effects, and the prices don't capture the costs. Other advances in dispatch and pricing give attention to the block loading and startup inflexibilities that require extended locational marginal pricing. What are the pressures that are driving dispatch models? How is the technology of renewables or conventional fossil plants changing to avoid or adapt to these new challenges? What generator, dispatch, pricing concerns might be pushing the envelope?*

*Moderator:* The issue of proper price formation is one that has occupied a lot of time in the industry, and a lot of time at FERC as well. I would say probably over the last 18 months or so the issues surrounding price formation has probably been, in terms of intellectual capital of the Commission, as big a lift as anything that we've been doing from a staff standpoint in terms of resources intellectual capital that's going into that particular effort. This morning session focuses on one subset of the price formation issue, which has to do with as we bring on more variable energy resources. Those resources have operational characteristics that we all know are different than the traditional way that we produce power, and some of those operational characteristics may not be reflected in the prices and in the market dispatch rules that we have. And there can be all sorts of potential consequences that we may want to keep an eye on as we look at one of these frontier challenges in pricing and dispatch.

#### **Speaker 1.**

When Dr. Hogan called me to invite me to this panel he encouraged me to be provocative, and I'll try to live up to that invitation. I think my

bottom line is going to be that cycling and the wear and tear cost associated with high penetrations of renewables are not a big deal. We have much bigger problems, which I will describe.

Just for those of you who don't know us, in terms of Calpine's portfolio, we have about 27,000 megawatts nationally, maybe closer to 28,000 at this point. We recently acquired another combined cycle in New England. Our portfolio is concentrated in California, Texas, PJM ,and increasingly New England--so largely the competitive markets, although I'm not sure California qualifies as a competitive market, and after yesterday morning, I'm not sure any of these qualify as competitive markets. [LAUGHTER] But our fleet is mostly modern combined cycles. Many of them are in combined heat and power configurations, and then we also have the Geysers, which is the largest geothermal plant in North America.

This is our fleet in California. Our plants are concentrated in the Bay area, where the company actually started. We do have a combined cycle down by Bakersfield and one in

San Diego, and you know the Geysers, which is north of Napa, on the border between Lake and Sonoma Counties.

To give a high level overview of my remarks, I'm going to talk about how the conventional generation is expected to operate under high penetrations of renewables, whether the costs associated with cycling are large or significant, and whether those costs can actually be recovered from wholesale markets. Then I will pivot to what I think is really the much larger question which is, in markets with very high penetrations of renewables and a lot of other types of subsidized entry, are the merchant economics really sufficient to support the continued operation of the conventional generation that's needed for reliability? And then I'll talk about some market design changes that are either already being implemented or being contemplated in California. There's some very positive energy market changes on the horizon and some potential changes to California's bilateral capacity market.

So what's going on with renewables in California? The upper left picture here shows what the three large investor owned utilities already have under contract to meet California's 33 percent by 2020 RPS, which was recently expanded to 50 percent by 2030, and so you can see they're well on their way. And not only are the renewables coming, but they sort of already arrived. So the upper right picture, the "Hourly Average Breakdown of Renewable Resources," this is just a snapshot of a recent day a couple weeks ago, and you can see that, routinely, we have six, seven thousand megawatts of solar showing up in the middle of the day. And this is just the utility scale solar. This doesn't include any of the behind the meter rooftop solar, which is probably another 3500 megawatts now.

So what does this do to the operation of the rest of the fleet? I tried to illustrate this with a slide at the bottom, and this is from a simulation of a 50 percent RPS. And I've seen the duck curve so many times in so many different presentations, I wanted to avoid using the duck curve. So this is the inverse of the duck curve. What you can see is how you get all this solar in the middle of the day--so that's the green. The green is the renewables and in the middle of the day. That's largely solar. And so everything else needs to be scrunched down in the middle of the day, to the extent possible. So you can see on the chart how the gas gets turned way down. It can't go all the way off, because it needs to be on to meet the big ramps that occur at the end of the day when the sun goes down and also might need to be on to provide some reserves in the middle of the day. The red is excess solar. That's solar that doesn't have a home. It can't be used to serve load. There's just too much of it. It can't be exported. So people who like solar call this picture the "sunrise" and people who don't like solar call this the "pimple." [LAUGHTER]

So a little more detail on how the conventional fleet might operate at very high penetrations of renewables. I just pulled some results from a recent study called the Low Carbon Grid Study. This was sponsored by CEERT, an environmental group, and a lot of the work was performed by NREL, the National Renewable Energy Lab. And, somewhat surprisingly, what it showed (and now I've seen this result in multiple studies) is, yes, high penetrations of renewables really reduce the capacity factors of conventional generation overall, but when conventional generation is committed it tends to run at a relatively high capacity factor.

And so the study looked at various penetrations of renewables--33 percent, 50 percent, and something approximating two thirds. The upper left set of charts shows summer and the upper

right is spring. The top of each of those pictures show combined cycles. I'll focus on those results. The solid lines are the committed capacity and the bars are how much energy is being produced by that committed capacity. And so you can see, at least in summer, the unit commitment don't change that much. In other words, units aren't necessarily starting and stopping all that much, and once they're on, they run at somewhat high capacity factors. There's a bigger problem in the spring, when there's just a lot of solar, and load isn't very high. So meeting that net load shape with conventional generation becomes more challenging.

Somewhat counterintuitively, these results suggest that not a lot of cycling is going to occur at very high penetrations of renewables. Even if it did, there are some other results that suggest the costs really aren't all that high. This is actually straight the Western Wind and Solar Integration Study. And it shows that cycling costs--both fuel and things like wear and tear--are on the order of a dollar or two per megawatt hour of conventional generation, and the bottom half of this picture just aggregates by technology. So costs are pretty low for combined cycles, and pretty low for coal, because coal just doesn't cycle maybe all that much, in the simulations from which these results are drawn. Costs are a bigger deal for combustion turbines, because the run cycles for combustion turbines are shorter, and so the start costs are just higher per megawatt hour, because there just aren't that many megawatt hours.

Regardless of the magnitude of the costs, can these costs be recovered? In the CAISO tariff there are provisions to include costs associated with wear and tear and cycling in the start costs that generators give the ISO for their unit commitment and dispatch. So there is a way for generators to recover wear and tear. We can argue about whether wear and tear should be

reflected in clearing prices better, or whether it's going to be increasingly recovered through uplift, but there is a mechanism in place to recover these costs.

And if the costs were really significant, there are a lot of things that we could do to minimize them. So this is just a list of upgrades that we've considered to some of our combined cycles that would really mitigate cycling costs. And for combined cycles, a lot of the costs are really associated with the steam part of a combined cycle--exposing it to a lot of thermal stress you know, in general. It's not good to expose thick pieces of cold metal to really extreme heat. And so a lot of the things that we would do to make combined cycles more flexible involve keeping that thick metal warm. Like putting thermal blankets on the steam parts of a combined cycle, or we can even use steam bypass when we start a unit cold. You know, just basically condense the steam without running it through the steam turbine until the steam turbine starts to warm up. And we sort of try to estimate the cost of all the things that we could do, and it would be on the order of \$100.00 a kilowatt. So there are low cost flexibility improvements out there if cycling costs or other operational flexibility needs manifest.

So basically I think we have bigger fish to fry than cycling costs. And I'm afraid that I'm going to end up sounding like many of the presenters yesterday morning, complaining about how coal can't recover its cost and nuclear can't recover its cost. In California, gas can't recover its costs because there are so many renewables coming in the market. And so I just wanted to briefly summarize the current economics of merchant conventional generation. So the to chart here is an estimate that the ISO prepares every year, and it shows how much a generic combined cycle plant could be expected to earn in energy and ancillary services from CAISO markets. And

that sort of has hovered around \$40.00 per kilowatt year. And we see that trending down as hydro conditions in California return to normal and as more renewables come on to the system.

Now, California now has a capacity market. It's not a centralized capacity market; it's a loosely structure bilateral capacity market. And I've summarized prices from that market in the table at the lower left, and it's very hard to read, but the left column is the average RA (resource adequacy) capacity price by month. And if you thumb down that whole 12 month strip, it's about \$30.00 a kilowatt year, which actually overstates what a lot of units are able to earn, because this is a combination of prices for system and local RA, and there are a lot of units that aren't in specific load pockets that would generally earn less than this, or might not be able to sell RA capacity for all 12 months. So we've got sort of the \$40.00 per kilowatt year in energy and ancillary services probably going lower and say maybe like \$20.00 per kilowatt year for capacity. That's really getting pretty lean, pretty close to the going forward costs, actually, of many merchant combined cycles, especially since a lot of the merchant combined cycles in California were built at the beginning of restructuring in the early 2000's. They're facing major maintenance. The supplier would typically amortize those costs over multiple years, but because there's so much uncertainty in the California market and the compensation has been so low, it's very hard to incur those costs and expect to recover them over multiple years.

Just to put a finer point on this, I think this is a perfect window into California. This is a picture that we shared with investors on a recent earnings call, and it shows where we make our money in California. So, the 725 megawatts of renewable capacity at the Geysers counts for 55 percent of our free cash flow in California. And

then the approximately 2,000 megawatts of conventional generation that's under long term contracts (I guess in other markets those would be called out of market contracts) accounts for another 40 percent of our cash flow. And the remaining 3,500 megawatts of capacity that is truly merchant yielded about 30 million dollars in cash flow last year.

And in the interest of time I'm not going to go into this in any detail, but the reason we should care about this is that California is going through a major transition of the generation fleet. It's not just that we're bringing on more renewables. It's that we're going to get rid of 10,000 megawatts of older gas fired steam generation over the next five years that will be forced to shut down to comply with once through cooling regulations. You know, the shutdown of the states remaining nuclear power plant, Diablo Canyon, 2300 megawatts, is somewhat likely. So once all that stuff is gone, the remaining more modern gas fired generation will be really critical, and so we should care that it remains viable.

Now, there are some positive developments that might enhance compensation for merchant conventional generation in California. I'll touch briefly on a couple of energy market reforms. One is CME (contingency modeling enhancements). Basically, it's an attempt to reflect reliability related unit commitments, like if the CAISO just has to have a certain amount of capacity online in a particular location, it's an attempt to get those kinds of commitments reflected in clearing prices. I've no idea how much this will eventually yield.

There's also something called flexiramp. Basically, the CAISO sets aside capacity that might otherwise be economic for energy to ensure that it has sufficient operating range to accommodate uncertainty in load and renewables, five, 10, 15 minutes out. And

flexiramp is a way of providing an explicit payment for that capacity reservation. And so this has been implemented as a constraint, not as a separate product in CAISO markets for the last few years. It's soon to become a formal product. It's not obvious to me that this is going to yield a lot of revenue. The constraint in 2014 yielded about six million dollars in payments to suppliers, I believe. And I'm told that the new product is going to be much more remunerative, so that's great, but I'm still not sure there's a lot of money here.

With respect to the capacity market, California has this relatively new flexible resource adequacy capacity product. In our capacity market, load serving entities have to buy capacity at the system level. They also have to buy capacity in certain load pockets, and now, they also have to buy capacity that can ramp over three hours. And I think the intent of flexible RA was actually to direct more resource adequacy procurement and more revenue towards modern, operationally flexible units. And for a variety of reasons that hasn't turned out to be the case. The way the product is defined, it's way over supplied. It's just not scarce, so it basically trades at the same price as plain vanilla capacity. I think there's 30,000 megawatts of potential supply, and the maximum requirement in any given month is like 10 or 12,000 megawatts. And part of the issue is how different types of resources count towards the requirement. Like the old steam units count a lot for flexible RA, because they have very low min loads, and they generally have really wide operating ranges, so once they're on, they can ramp. But the rules don't account for the fact that in order to have that steam unit available to meet ramp, you need to have started it yesterday or days ago, and potentially run the unit out of merit and incur all these uplift costs. If you fail to start the unit ahead of time, it just won't be available to meet

ramps, because it can't start fast enough. So from our standpoint flexible RA has been kind of disappointing.

There are changes that are being contemplated. The CAISO pretty consistently has indicated that the current three hour product is really a crude proxy for a bunch of different requirements that they actually have, and so they talked about, "Maybe we'll have a three hour product and a one hour product, and force people to buy capacity that's also capable of providing regulation." That gets very complicated and difficult, especially in a bilateral market like California. It's just virtually impossible, especially for smaller load serving entities, to comply with all these requirements and to trade.

An alternative approach might just be to get rid of flexible RA completely and rely more on the energy and ancillary services markets to reward capacity that's genuinely operationally flexible.

And then there are just some big changes to the generic RA market that I think will help. Probably the single biggest change is that we way overcount renewables towards resource adequacy requirements right now. So, solar generally counts at about 70 percent of its nameplate capacity towards resource adequacy requirements. And that's for historical reasons. The current rules reflect the average performance of solar during a set of traditional peak hours. But, you know, now that we have 7,000 megawatts of solar on the system and 3500 megawatts of PV behind the meter, the reliability problems are not in the middle of the afternoon. They're in the late afternoon and early evening, once the sun goes away. And so state law actually mandates that the public utility commission implement a new methodology for determining the RA value of solar and wind, and they've been working on implementing that

methodology for three or four years now, and it seems like it's finally going to go live either this year or next year, and that will help a lot.

The second thing here is a little bit more nebulous. I alluded to this earlier, but maybe there's some way of managing the rationalization of the conventional fleet a little bit better. There are a lot of older steam units that are procured to meet resource adequacy requirements, but we know they're going away. And we have a lot of more modern conventional generation that doesn't get procured as RA now, even though we know we'll need it later. And there are reasons for that. A lot of the steam units are in important locations for local reliability, but not all of them.

And so, is there some way that we can manage the transition better and direct some procurement towards the resources that we're going to need in the future, rather than the resources that we know we're getting rid of?

And, finally, greater clarity about Diablo Canyon, the nuclear plant, and whether it's going to shut down or not would be very helpful. If it's going to continue to operate, then maybe more conventional generation can shut down, but if it's not, it would be good to provide that certainty that we're really going to need most of the modern conventional generation after it's gone.

**Speaker 2.**

: I agree with a lot of what Speaker 1 said, and I guess I have a few differences, also, with what he said and I'll try to explain that in my talk.

The work that I'm going to be discussing today comes from a set of studies that GE, NREL and Entertec did a few years ago. It was the *Western Wind and Solar Integration Study, Phase Two*, and we were specifically looking at this idea of

coal and gas plants cycling and what are the costs, what are emissions impacts, what are the causes of this, especially in relation to the wind and solar induced cycling, because as you know, cycling occurs even without wind and solar. So the report asked what extra impact wind and solar caused to the system.

So we all know there are actual wear and tear cycling costs that are largely driven by changes in temperature in the components that basically cause metallurgical fatigue, and the more temperature change the plant experiences, the more damage to components and the more costs are experienced. So a cold start, for this reason, is much more damaging and costs more than a warm start, which in turn costs more than a hot start, which in turn is worse than, say, just ramping the plant from a 100 percent output, say, to 80 percent output or partial loading.

So it's difficult to quantify the cycling cost. And one of the reasons it's difficult is that if you do a cold start on your plant today, you may not realize the damage or the increased need for maintenance and overhauls or the repairs and replacements of components until several years down the road. And so it's very difficult to determine the causes of those costs that are realized much later. And in order to actually go and determine the cycling costs for a particular plant...first of all, all plants are different and you really need to look at your own specific plant to determine the cycling costs of your specific plant.

In order to do these kinds of studies, we hired this company, EnerTech/AbTech, who does this for a living. They've evaluated about 400 plants around the world, and it takes about a year's worth of time and a couple hundred thousand dollars to do the study, where they go and they look at decades of records of operations and repairs and maintenance and overhauls, and they

have a rainfall damage account model that basically determines those cycling costs.

We didn't have time to go and do that for every plant in the West. So we asked them if they could take their database of plants that they had studied from around the world and do some statistical analysis on that and give us some generic cycling costs from that database. So this, these cycling costs that I'm showing here and the ones that we used in our study come from those analyses. Basically they divided their database into different categories. And for each power plant that they study, they determine the lower bound and an upper bound of cycling costs and a sort of best fit in their reduction analysis. And what you see here are the lower bounds by type of power plant. And this is just showing cold starts, but you can see that the median lower bound for the small subcritical coal plants that they looked at was about 150 dollars per megawatt. So if you had a 100 megawatt small subcritical coal plant, that would mean you'd be paying \$15,000 every time you did a cold start for that. And, again, this is just the lower bound of the cost. There's also a higher upper bound cost as well.

And they did this for cold starts, for warm starts, for hot starts, for ramps, and also for damage that was incurred in terms of affecting your equivalent forced outage rate. And so there are different kinds of damage that can be incurred.

So the first thing we looked at was what happens when you use these cycling costs versus not using these cycling costs. Because a lot of folks don't have cycling costs for their plants. They don't actually use them in the optimization of unit commitment and economic dispatch. What's the difference? The big difference that we found was not in the energy that was generated by coal or by combined cycles or CT's across the region, but it was in the number

of starts. So in the zero wear and tear case, you can see that you start up the gas combined cycles and the gas CT's far more than you do when you actually include the cycling wear and tear costs in that unit commitment decision. And, again, the total energy from gas CCs didn't really change, so the gas CCs were incurring more costs in this scenario, while not necessarily incurring more revenue from the energy markets. And because of this, we think it's very important that these kinds of wear and tear costs be included when you make those unit commitment and economic dispatch decisions, because there are real costs that accrue to the generators, and if they're not making as much money in energy to cover those costs, then this can create financial issues.

As Speaker 1 mentioned, the cycling costs are not huge. So if you compare the cycling costs to your overall production costs, we find that cycling costs are a few percent of overall production costs. So they're not huge compared to overall production costs. But if you take those cycling costs, and you attribute that to each megawatt hour of generation of a fossil fuel plant, then, as Speaker 1 was saying, the fossil fuel plant is seeing an increase in their O&M that could be something on the order of a dollar per megawatt hour. And, as Speaker 1 also mentioned, if you're adding renewables to that system (and we were adding about 33 percent renewables in high renewables cases), you're generating less energy, and you may be seeing an increase in your O&M, and the combination of these two factors could impact your financial viability.

So one of the things that we were looking at was trying to understand the impacts of adding wind and solar and how that impacted cycling. Some looked at dispatch. And during the worst (most stressful) week, in the spring when you have a lot of wind and you have a lot of solar and you

don't have much load. And what you see on the top is our no wind and solar case. So you take out the wind and solar, and you've got nukes, coal, hydro, and gas combined cycle units. And as you add in these high renewables scenarios, you see different dispatch.

So in our high wind scenario, it's 33 percent annual average energy from wind and solar, and 25 percent is wind, and eight percent is solar. So it's mostly wind, with some solar. The first thing you notice is that basically you've displaced nearly all of your combined cycle generation. And you're starting to displace, over the course of this week, a lot of the coal generation as well.

In the high solar case we basically flipped the wind and solar ratio. So we've got 25 percent solar and eight percent wind. In a high solar case, again, you've displaced the green, the gas combined cycle generation, and you're backing down your coal every day in the middle of the day to accommodate all of the solar. And in addition to backing that down, you actually have curtailment of the solar. We're actually having to curtail solar in the middle of the day as well as backing down the coal, even sometimes backing it down to mingen.

So wind and solar have different impacts on cycling. We looked at the impact on cycling for coal units. The coal plants are actually backed down quite a bit. And in the no renewables case, coal is basically running flat out at 100 percent output. And in the high wind case we are de-committing the coal over the course of this week to accommodate the wind. In the high solar case, we're not so much de-committing the coal as we are just backing it down, dispatching it down every day, in the middle of the day, to accommodate the solar. So the impacts of what wind and solar are doing to the system are different. With the coal we're perhaps de-committing and doing more starts. With the

solar we're perhaps backing down and doing more ramps.

We also looked at which units gets started more often. As you go from the no renewables case to your high wind case, one of the first things we noted is that you're actually reducing the number of starts of CTs in the high wind case, and some of this is due to the fact that you're actually getting some of that wind in the evening, when you might otherwise be starting up a CT. And then we also noted that we're getting some increased combined cycle starts, and there's also some increased CT starts in the high solar case as well. And I also note that with the gas combined cycles it wasn't like the small units were being jerked around a lot, as we thought it might be, but rather some of the large units were actually being moved around.

It's not just renewables that are causing these kinds of changes and differences. If you look at differences in natural gas prices, this significantly impacts cycling.

So we did the bulk of the study with a gas price of 4.6 dollars per million BTU for natural gas. And then we did a sensitivity analysis, where we took half of that gas price and where we doubled that gas price just to see what the difference would be in terms of cycling impacts. And what we noted is that when you double that gas price, to 9.2 dollars, you significantly increase your gas combined cycle starts. And if you halve that gas price, to \$2.30, you significantly reduce the starts and the gas combined cycles. And that's because at this point, the gas combined cycles are becoming your baseloads. You're basically running them as baseload. And so you're starting them less.

Now, if you look at the cost of that cycling, the really interesting thing to us was that, with the high gas price, in going from the no renewables

to the high renewables scenario, you're actually decreasing your overall cycling costs in that high gas price scenario. And similarly in the no renewables and the high mix case for the low gas price, you're actually slightly decreasing the cycling costs there as well. It turned out that we just happened to pick a gas price for our baseline runs as \$4.60 that happened to have an increase in cycling costs when you added in the renewables.

But the point of this is that there are a lot of interactions in these systems. There are a lot of different factors. It's very difficult to pull out any simple answers in terms of different impacts of different things, because it's a very interactive system. And so gas prices have an impact. Renewables have an impact. I want to show also a case study of some plants that had nuclear cause their coal plants to have to cycle quite a lot, and adding in any kind of zero or low marginal cost generation that pushes everything else up the stack is going to make everything else have to cycle.

So this case study that we did was driven by the fact that we were working in the West. We were working with a lot of coal plant owners who said that their coal plants could not cycle. They were designed for baseload operation and that they weren't able to do the kinds of operation that we thought might be needed. And we went to do a case study of a particular coal plant, and this particular coal plant owner operator has a number of coal plants that, because of nuclear coming in as the least marginal cost and driving the coal up the stack, they were having to run these base load coal plants as load following units, and then peakers, and then actually super peakers.

You might be familiar, for example, with two shifting operation on a plant, where you need to turn it on and then turn it back off in one day.

They had to actually four shift their plant sometimes, and they were actually able to run this particular plant that we saw down to less than 20 percent minimum generation levels. So they were able to do quite a lot, and get a lot of flexibility out of their fleet. They were able to actually run their coal plants to provide regulated reserves. So there were quite a lot of interesting lessons learned from this particular operator, and there were a number of physical changes that were made to the plant. Once the physical changes were made, they were able to get a huge amount of plant savings just from changing operating procedures. So, for example, how you do your layup on the plant and whether you use nitrogen blanketing and how you cool the plant. Whether you try to force cool or use natural cooling. There were a lot of procedural changes that actually helped them to be able to operate their plant in this fashion.

So one of the big questions that folks ask is, does it make sense to retrofit my plant to increase flexibility, and what are the economics of that? And as part of this we did a coal gas retrofit study where we looked at the Rocky Mountain region and examined retrofits specifically intended to lower the minimum generation level of the plants. And we found that by lowering the minimum generation level of the plants, we did have system level net benefits for these retrofits. But we also did find that those benefits were very specific to each plant. So, for example, some plants had a lot of benefits. Some plants actually didn't have benefits, and so it really depends on which plant and where that plant is in the dispatch stack as to what kinds of economics you would have for your plant.

So in conclusion, I think that wear and tear costs are real costs that are incurred by generators. They're very generator specific, and these costs can increase or decrease depending on how the power portfolio changes or fuel prices change.

And if these costs are not compensated they can impact the financial viability of generators, especially as other changes may be taking place. It's important to incorporate the cycling cost and the commitment costs in dispatch decisions, because they change what decisions are made, and wind and solar can have different impacts on cycling. And then, finally, there are different kinds of physical changes and operational changes that you can make to increase flexibility, and, depending on your individual plant, retrofits can help you increase overall profitability.

I guess maybe some of the difference that I might have with Speaker 1 on some of the conclusions is that, while the costs are not huge, if they're not compensated, that can be problematic. I spoke to a director of market operations from a utility last week who said that in MISO he's able to recover his wear and tear cycling costs, but in PJM and SPP he's not able to recover that. And so that's causing issues, because he feels his plants are getting started more often. He needs to be able to recover those costs, and there's no way for him to figure out how to do that. So, depending on which market you may be in, you may or may not be having a problem with this. Thank you.

**Speaker 3.**

Good morning everyone. Thanks for the opportunity to participate in today's discussion. I'm happy to be here. My remarks will be from the perspective of a system and market operator.

So, the flexibility costs generators may face today may grow larger and become more significant in the future, and will market rules give them the opportunity reflect and or recover those costs? From their perspective that's the first and foremost concern, and from the market administrator's perspective as well. What's the opportunity to recognize those kinds of costs and

appropriately reflect those in the market clearing prices?

We found at MISO, from the initial days of our operations, that if the system operator does not do that well, these costs may not be huge in the overall scheme, but if asset owners find that they're not being compensated for the real costs that they incur, the easiest thing for them to do is to start withholding the flexibility that the resources might otherwise be able to provide from the market operator. They reduced ramp rates offered. They may increase offered prices for commitment costs. And for the 10 plus years that MISO's been operating a market, we know that the availability for us as a market operator to access commitment and dispatch flexibilities is essential and critical to our core mission, which is delivering cost effective reliable system operations to a relatively, or very large market footprint.

To give you a quick verbal description of MISO, MISO operates wholesale power markets over all or parts of 15 states, covering the Central and Western portions of the Eastern Interconnect, stretching from the Canadian border down the Gulf of Mexico. Our market has about 175,000 megawatts of generation in the footprint that competes to bring energy and ancillary services. That represents about 2200 plus individual generators that are bidding into our day ahead and real time markets on a real time or an hourly basis. Those generators are competing to serve a peak load for our system of about 130,000 megawatts, which is our summer peak. Our winter peak is lower, and it's about 110,000 megawatts.

Again, we're operating both day ahead and real time LMP markets. Our offers for our generators include three part offers. So in addition to an energy use capacity offer, in our markets our generator owners are able to provide startup and

no load offers as well, which are factored into the unit commitment optimization. So the fact that we have the three part offers allows generators, if they're able to understand and calculate and estimate their startup and cycling costs, to provide us that information, and it's included in the decision making of optimizing those commitment decisions.

We have taken some steps with our market price formation capabilities over the last year and introduced extended locational marginal pricing, which allows some units to include their start up cost to actually have an impact on the market clearing prices. So as a market operator we're interested, from a price formation perspective, in when it's appropriate to identify the value of those services which could include start up and no load costs and find appropriate ways to reflect that in market prices. That has another benefit of potentially reducing market uplift charges or unrecovered generator operating and commitment costs under LMP that are incurred.

Speaker 2 showed some slides where different markets were modeled. One market didn't have much wind. One market with wind. Speaker 2 talked about the impacts of gas prices. But in the 10 years that MISO's been operating in market, we've lived all of those realities. So, from the period from about 2005 to 2008, the MISO market was dominated by coal fired generation and nuclear generation. At that time about 75 percent of our total requirement came from nuclear and coal. Nuclear units are historically not very flexible, either from a commitment or dispatch perspective. Coal units are generally a little more flexible, but not considered completely flexible in either regard as well. So even early on, we had a need for a flexible resource as the load pickup in the winter. On the coldest winter mornings for MISO, we'll pick up 35 to 40,000 megawatts in about a four hour period. So even with just nuclear and coal

predominately online meeting requirements, we had, even in 2005, a significant need for flexible resources to commit and stage and bring online over a four hour period each morning, where we're picking up 7500 megawatts in each hour. So flexibility has always been an essential need at MISO from an operator control room perspective.

The 2008 to 2012 period was the period for MISO characterized by pretty rapid wind integration. In 2008 we had on the footprint just a couple of hundred megawatts of wind resources. By 2012 we had 14,000 megawatts of wind. In terms of the variability that comes from wind in the context of MISO, I can walk into a control room and look up and see 80 megawatts total wind on the system today. The next morning I can walk in and I'll see 12,000 megawatts of wind. Fortunately, forecasting of wind output is pretty reliable. So over that timeframe, even a 10,000 megawatt change in wind production, we can forecast that pretty well. As long as we have units that are flexible, we can plan for and commit around those changes in wind.

Today we don't have much solar on the MISO system. Maybe a duck curve is coming to a Midwest market sometime in the future. I understand solar is a little more challenging in terms of predictability, so that will create even more need for flexible dispatch and commitment capabilities.

So from our perspective, as we think about this ongoing need for flexibility, from where we sit it looks like that will continue to be a need, if not grow as a need. And the premise of our discussion is, what challenges does that create? How to avoid unnecessary cycling of baseload units, or to the extent that we do that, can we incorporate the actual additional costs of cycling? Pricing. As we move forward in time,

with the addition of wind and other very low marginal cost resources, how does that change the future environment, in terms of a low marginal cost environment where I still have a need for a lot of flexible resources to be online, maybe at a higher marginal cost? Is the market construct in pricing formations flexible enough to have those units online needed to provide that flexible ramping service and appropriately compensate those units?

I'll talk a little bit about our ELMP experience. As we looked at the traditional LMP price formation, it's based on a notion that the clearing prices for the market are established just based on the energy offer prices for resources. They start up and no load components of overall costs for units have not historically been able to participate in market clearing and price setting. Not unlike other LMP markets the challenges that we found with that include certain resources, particularly very fast commit and fast rampable resources. Again, there're only participating in price setting with their energy offer, but as their flexibility is so great, and you bring that into the commitment decision for a faster resource in real time, it starts to feel more like an incremental marginal cost price type unit that you could reasonably include in your market prices. A lot of those units, as well, don't have a large dispatch range available to the market, and those units historically are not able to participate in price setting. There's a situation where some units, especially fast start resources that are offline, are in a position where, from an efficiency perspective, you might like, under specific circumstances, for offline resources also to participate in price setting.

The other issue we have is around pricing of demand response. It's not been a practical issue for MISO since we've not deployed a demand response from a commitment or a MISO deployment perspective in over 10 years. But as

reserve margins start to tighten up we expect that we'll be needing to deploy those resources more often going forward, and the price formations historically don't allow demand response, at least in our construct, to participate in price setting.

And I mentioned uplift payments earlier. Units that have real startup and no load costs may under an LMP market not fully recover those operating costs and in those cases, those units are eligible for a make whole payment to compensate them for the revenue that they didn't receive that adds up to their total cost. So, again, as a market design consideration we're interested in minimizing those costs as best we can, so naturally at the bottom ELMP put those forward design objectives front and center as we developed with our stakeholders the formulations for ELMP.

So here we are on our way. I know what the past looks like. What's the future going to look like? Again, am I walking towards a duck curve here in the Midwest? So ELMP was initially and purposefully designed with our stakeholders to be developed and delivered in phases from a couple of perspectives. One was just a risk minimization perspective. This is a new pricing formulation. It has the potential, or had the potential, depending on how you designed it, to result in significantly different clearing prices, compared to what market participants were used to, so we actually designed phase one to be a very conservative implementation.

We have found over the last year of operating with ELMP as our production pricing formulation that it was very conservative. The actual impacts have been very, very modest on ELMP pricing, compared to what the LMP pricing would have been.

Not only was it the conservative design that led to the outcome so far. It was also driven by the fact that we put this in place in March of 2015, and we've had an extremely mild summer last year and this winter's been very mild as well. You would expect to see ELMP separating from LMP prices when you're at higher load operating conditions. When you're taking actions to commit faster start resources under those conditions you see more of a separation.

Well, what we have learned is that, though the impacts were very modest, everything, directionally, has proved the theory that was put in place. So prices move in the right direction. We have seen reductions in uplift payments as a result. Though they were small, everything that we've learned has validated the theory that was worked on for quite some time before we put this into production.

So at this point, just to give you some numbers, the delta ELMP versus what the LMPs would have been has been less than a dollar increase impact. The biggest impact comes from the offline participation piece. MISO runs a discrete five minute unit dispatch. Since they're discrete, the system doesn't have the ability, really, to manage available ramp capabilities. So you can get into situations under LMP where you get these transitory market price spikes. You'd be right along at \$20.00 prices for many, many intervals and then you'd see a pop up to three or four hundred dollars that would last five minutes and it would come back down. That was driven by transient ramp shortages that were lasting five or 10 minutes. The optimization of our commitment and dispatch is to minimize total commitment and dispatch cost. And from that perspective it was the right answer. The system operator could have committed another unit in advance to mitigate that five minute shortage, but that really would have increased total cost.

So we had a situation where the operator knows he's going to have insufficient ramp in five minutes, he chooses not to impose on the market the cost of committing a unit to mitigate that. So in that very narrow circumstance, ELMP could look at an offline resource and say, "That unit can participate in price setting." In those circumstances, it's less than one percent of the intervals that we run. We've seen a \$15.00 per megawatt hour reduction in LMP--ELMP is lower than what the LMP would have been. So that's the biggest price impact we've seen so far.

We just kicked off a conversation with our stakeholders this month about phase two. The current rules allow units that have a 10 minute startup capability and their minimum runtime is an hour to participate in price setting. That is 90 units on our system. Again, we've got 2200 units in the fleet. That applies to 90 units. That's about 3,000 megawatts total. If, in phase 2, we extend that participation to units that have 30 minutes or less startup capability, even keeping an hour minimum runtime, we can expand that to between 200 and 250 units and take it up to almost nine to 10,000 megawatts participation. We're currently doing studies to look at the impacts of making those changes, and I believe that it's going to be suggested we should move in that direction, and we think we can put that in place in 2017.

So, recognizing, as we have, the value of flexibility both at commitment and dispatch, we've taken steps since 2005 really to make improvements in this area from the generator's perspective of being interested in being fairly compensated for all the services they provide to the market. Here are just a few recent examples. In 2012 we implemented regulation mileage payments. This is a specific process for compensating directly generators that are cycling. In this case we're providing regulation service. We've learned quite a bit from that

implementation, and we think that maybe there are some extensions of what we learned from reg mileage, in terms of direct compensation for cycling or work performed, that we could apply, possibly in the load following timeframe. MISO's adding this spring a ramp product that's not unlike the product that is in California. This is a 10 minute look ahead. So our UDS (unit dispatch system) algorithms will specifically identify known and make estimations or reservations for potential unknown ramping requirements up to 10 minutes in the future, to the extent that there is a limitation of ramp. There will be a binding of this constraint. It will create a shadow price. We will make a reservation, we will hold back rampable capability for future needs 10 minutes in the future. That would be in the ELMP phase two I mentioned earlier. Possibly phase three or phase four.

You can continue to increase the number of units that can participate in price setting under ELMP. Some of the other things we're working on include cycling of baseload units under current day ahead commitments. So at any time, out of a hundred units that are online, 99 of those units were committed through our day ahead market. We currently run a 36 hour optimization in our day ahead market. There are potentially benefits to be gained by extending that optimization window. So we could move that out to 60 or 72 hours, and then you could even factor in and optimize multiple commitments for individual units, not just traditional gas units that have more commitment capability, but even for some coal units you could optimize multiple commitments over that time period.

I mentioned possibly incorporating this concept of mileage, and direct payment of cycling. We're thinking this might make more sense for this new ramp product. Again, you could make

ramp reservations for measuring the future ramp that was actually deployed for those resources. You could measure that work and incorporate a mileage offer perimeter that the asset owner could submit that could be factored into the optimization as well. So that's another potential area where we might be able to directly compensate for additional cycling requested of units.

Extending the market to longer response time is another possibility. I mentioned that the current ramp product is only going to make reservations 10 minutes into the future. That could easily be extended to 20 or 30 minutes as well.

Full LMP, this again is this notion that every unit is participating in price setting with their full load cost amortized over their runtime. So that potentially could happen in phases three, four and five. I think that's everything I was going to share today. So I look forward to the discussion.

**Speaker 4.**

: Good morning everybody. First of all, this is my first time at HEPG. My first time at the panel and my first time being invited, so I wanted to thank HEPG for inviting me and especially William Hogan for giving me the opportunity to talk to you all about my research on cycling costs and fatigue on combined cycle units. So thank you very much.

Well today I'm here to talk to you about some research on assessing the impact of cycling costs on combined cycle units. In Spain we have a peak demand of around 40 gigawatts, and we have around 25 gigawatts of combined cycle power plants installed, which is maybe 20, 25 percent of the overall capacity. These combined cycle power plants were constructed usually during the beginning of the 2000's, when there was kind of a boom where everybody thought

that the demand was going to be growing a lot. And so when they were constructed really, the idea was that they would be operating almost at baseload plants. So the idea was that they were going to be operating at around four to five thousand hours a year.

Things have changed, ever since the economic crisis, which has had quite an impact on Spain especially. Demand has not only not been growing, as a matter of fact it has been declining. And so many of the combined cycles that we have right now are running at less than 10 percent of their capacity and are being used very, very little. And what they're being used for right now is to counter balance the fluctuation that we have in that demand due to the high wind penetration that we have in Spain, where we have around 20 percent of wind generation in the market.

So the work that I'm going to present here today is really trying to answer a particular question. When we designed our combined cycle plants, they were kind of supposed to be convertible cars going on a highway at a particular speed, and now we're using them as four wheel drive going up a bumpy mountain road. And the question is, how is this affecting our convertible cars? So how is the wear and tear effecting these units?

In general in Spain, when you look at combined cycle operations, you have two worlds. You have the world of economics and you have the world of power plant operations. So usually the economic side would be you bid into a market. You try to maximize your profits by bidding into the market, and once this operation has been decided then it goes to the power plant operators who know their plants, who are the guys with the white helmets who actually run the power plant, and they try to run their power plant at minimal cost.

So in CCGT operations, step one, they bid into a market. Usually the people who bid into a market in Spain are not the people who operate the plant itself. It's an economic department. People who sit in an Iberdrola or in a site in Madrid in an office, and they place the bid. Then afterwards the market is cleared, and the overall generation and prices come out of the market clearing process. And this cleared production is forwarded to the power plant operators and they then have to operate their scheduled output, and obviously they try to do that at minimal cost. And then the firm that owns this generator earns the market prices for this.

The question that we have is that since there is this divide, this separation between economic decision making, this economic dispatch, and actual power plant operations, we were wondering whether this separation was actually causing issues for the generators themselves. A colleague of mine who worked at the Columbian transmission system operator told me that a lot of times in meetings the economic side of a company and the operators of the power plant would get into fights about how they would operate the plant, and then they would have to take it outside... [LAUGHTER] But I'm not sure I was supposed to tell that story. I'm not going to say who he is anyways.

So the question that we wanted to know is, in a market where we have increasing penetration of renewables, is this divide between the economic side of decision making and the actual technical operations, is this going to cause a problem for our system?

Speaker 1 said that he didn't want to bring up the California duck, so I thought I would do so. But really not to annoy him at all, just to say that this is not what I'm going to be talking about. [LAUGHTER] The problem that there is in

California, the ramping problem, is not what I'm going to be talking about. In Spain we have a lot of wind, and what I'm going to be talking about when I talk about cycling cost and fatigue is really the overall wear and tear on the actual components of the power plants. So using our convertible car on a mountain road, how does this affect our car?

And answering this question is not a trivial endeavor. As Speaker 2 pointed out in her talk very, very nicely, calculating the actual wear and tear costs of a thermal power plant is not an easy task. Because I'm not talking about long term service agreements which might exist between generators and manufacturers of the gas turbine, for example. I'm actually talking about the thermal stress that you might have on specific components of your power plant, for example on the heat recovery steam generator, which is what we were focusing on. Because in Spain when there is an unscheduled outage of a combined cycle plant and unscheduled maintenance, the majority of the times that this happens for the combine cycles in Spain is due to failure, not in the combustion turbines, which are covered under the long term service agreements, but really in the heat recovery steam generator, or specific components within this heat recovery steam generator.

In order to actually be able to monetarize these costs, as Speaker 2 was mentioning, you have to be able to accommodate the fact that really every combined cycle power plant is different. Like every human being almost.

With combined cycle power plants it depends very much on what type of operation they've been designed for. If they have been designed to actually take into account cycling, which might well be the fact in California, then the way in which the manufacturers of the heat recovery steam generator actually build their component

is very different from a combined cycle plant that has been designed to function for 500 hours a year. And then in order to actually be able to calculate these wear and tear costs you need a company--in our case we had some collaborators--a private company who is dedicated to calculating exactly these costs. And they had access to the generation of one particular power plant in Spain. And they were calculating the actual costs of the thermal stress, and through the different generating data that they have they were able to identify the actual accumulation of fatigue during operations, which is information that they've shared with us for this project and which is the reason why we were actually able to do this study.

So the study that I'm going to present is something that is very tailored to one particular combined cycle power plant. And if you have a power plant that is similar in configuration, then it's not necessarily going to be exactly the same, because in the world of thermal fatigue it also depends on how you weld the specific pipes. So things can change quite a bit.

We looked at a problem that's called the unit commitment problem--the economic dispatch, let's say. We wanted to know if, given a specific operating schedule that has come out of the market clearing process, how would we operate our CCGT in a cost minimal way? That is, taking as given that we could not actually decide whether we wanted to operate or not, putting ourselves on the technical side of the story. When doing this type of problem we had to go into a couple of technical details in order to be able to introduce these additional costs of wear and tear or fatigue costs into our model, so we did that.

So let me just quickly show you a flow chart of the different operating states that we designed that the power plant could actually go through.

Within these “operating modes,” as we called them, we differentiated not only between whether our combined cycle was going to do a hot start or a warm start, but also between types of hot start. Within a hot start you have different alternatives of how you could start up your gas turbine. There are different power trajectories that you could follow which impact your plant and the fatigue that you’re going to have in a different way. And so we really wanted to model each of these different trajectories in our self-unit commitment model in order to have more flexibility and see really what type of operation would incur the least fatigue for our power plant itself.

So then the numerical tests that we’ve carried out are in some ways similar to what Speaker 2 discussed. What we wanted to do is examine how the CCGT would operate, taking into account these costs of fatigue. And what happens to our operations and to our overall costs if we disregard these costs of fatigue, which currently in Spain are not being factored into the bids that we have in the market?

So here we have one week of operation of a CCGT and we’re looking at this operation in 10 minute time increments (even though the market is cleared hourly), just in order for us to really be able to capture these different start up trajectories of the combined cycle power plant which might alter in on the five minute or 10 minute scale. We’re going to also assume that we cannot influence the bidding process, that the bidding process has been done by the economic department of our firm, and that we are essentially given an overall generation profile that we have to cater to. The prices have been decided in the market, so what we’re going to just decide how we’re going to get to this power output in a cost minimal way.

So what you can see here in this table are the different cost concepts. The first column that we have identifies a variety of cost concepts of this one week of operations, taking into account the actual fatigue that we have in our combine cycle (categories include total cost, no load cost, linear variable cost, ramp fatigue cost, transition cost, and deviation cost). And then the column to the right would be how are these cost affected if we disregard that we have these cycling costs and we disregard that we have these cost of fatigue? And we’re giving here the absolute numbers and in parenthesis also the percentage amount of total costs of these different concepts.

So the concepts that specifically take into account cost of fatigue are two, and they’re called ramp fatigue and transition costs here. So the transition costs have something to do with starting up and shutting down the units, and the ramp fatigue costs have something to do with, once you’re above the technical minimum of the plant, how quickly do you make your power plant ramp up and down? Because that might also have an impact. And so one of the things that I want to stress is that in general if you look at the terms that are affected by thermal fatigue, and you take into account fatigue in running the plant, you might have 1.2 percent of your overall costs that might be affected by these cycling issues. However, if you ignore that you have these issues, then it’s not 1.2 percent of your overall costs anymore, then you’re operating sub optimally, and you might actually end up having 3.6 percent of your overall costs affected by fatigue.

In general, these numbers are in line with what previous speakers have been saying. So the percentage amount doesn’t sound like it’s that big a deal; however, in the study that we’ve looked at we haven’t just looked at the percentage amount of total costs that these fatigue costs make up, but also at average costs

of production, So if later on we look at overall profit margins, then these three percent cycling costs have a substantial impact on how we operate the plant and also on the profit margin of the companies themselves. So, in general, if you're looking at average cost of production, taking into account these cycling costs, that results in a total power cost of 46.8 Euros per megawatt hour; and if you ignore these cost issues, that leads to higher average operating costs, and in particular it leads to operating costs that are approximately 47.9 Euros per megawatt hour. So that's a little bit more than one Euro per megawatt hour higher than if you were taking this into account.

So in operation you lose one Euro per megawatt hour by ignoring these effects, and if we translate this into actual profits of the company, average profits of the combined cycle decreased from 4.47 to 3.34 Euros per megawatt hour. And this decrease in profit margin is not three percent anymore. It's something that goes up to being 25 percent of your profit margin, which we felt was a substantial, or at least not a trivial, number to take into account. So even though the actual part of your total cost of cycling might be small, the impact that disregarding this particular amount has on your actual profit margins might be substantial.

So looking at how you should operate if you take into account that you have cycling costs and how would you operate if you don't, what we've seen is that overall decisions that we make if we don't take into account fatigue result in a lot faster ramping. And when you take into account fatigue overall, you try to ensure that your operations are smoother. So, for example, if you look at times step 160 in the first subplot, you see that when you take into account fatigue you start up your unit using a different startup alternative that might be getting you to your technical minimum a little bit slower, but the

effect that it has on your overall cost of wear and tear is a lot smaller.

So what I've been talking to you about up until now was the case as it is right now in Spain. And now we wanted to know, if renewable penetration is going to go up (it seems that this is the trend), then how are combined cycles, or at least the few ones that are actually still operating in the Spanish market, how are those going to be affected by increasing renewable penetration? And in order to come up with this case study is, we took a wind profile, and we said, "OK, if wind production goes over a particular percentage amount [which in this case we set at 40 percent] then we're going to assume that we're just going to shut down our combined cycle units."

Why did we do this in this way? Well, right now combined cycle units are really used in order to counterbalance wind. So if wind production increases, this might be a reasonable thing to expect for our combined cycle units, to just start up and shut down more frequently, and cycle even more. And in our analysis we found that with an increased amount of renewables, the impact on production costs is higher.

So what is one of the conclusions that we're taking away from this? That the higher the renewable penetration, the more it's going to hurt you if you disregard these types of costs in your per plan operations. And one of the results that we found that was quite curious, but also consistent with what is going on in Spain right now, is that average production costs increased. And if you remember, in the previous scenario, disregarding wear and tear cost you one Euro per megawatt hour, more or less. And in this higher renewables penetration scenario, it's costing you around three Euros per megawatt hour. So even though we have not changed the way in which we consider wear and tear costs in

our model, just the fact that our production output profile has changed quite drastically has increased the amount of impact that it has on our average production costs.

So assuming the previous market prices that we had, and just assuming that whenever the production profile is zero, we don't make any money, and we only make money when we're producing, we actually saw that this production profile would lead to negative profits. It would actually lead to losses of seven Euro cents per megawatt hour, which essentially mean that this plant would not be actually producing in the market if this were the production profile, because it would lose money. And if the plant operators didn't take into account wear and tear costs, then it would be losing even more money. It would be losing three Euros per megawatt hour.

So these numbers have let us to the following conclusions. First of all, taking into account wear and tear costs when you are deciding your optimal dispatch might be an important thing to do. So trying to bridge the gap between economic decision making and actual technical operations might be important, because you might be losing money here. And higher renewable penetrations and, in particular, wind penetrations in Spain, are making the impact of disregarding what is happening higher and higher. The wear and tear costs, relatively speaking, also increase. Average operating costs increase as a result of that, and this might lead to you having lower average profits or actually having losses overall, and might lead to you not wanting to actually produce in this market.

So we are asking ourselves whether, in a context where we have high wind penetration, we are remunerating the combined cycle gas turbines properly if we're not allowing them to factor these wear and tear costs that they have into

their bid. Should they themselves actually introduce this cost into their bid? And if we're not taking this into account, then with higher renewable penetration, are our combined cycles going to be producing at all? And if they are, what would be the price of production?

### **General discussion.**

*Question 1:* When we deal with issues like this, there's always a limited amount of resources and time that the market operators have, or FERC has, from regulatory perspective, just in terms of how we prioritize things. With respect to this particular issue, where does it fall in terms of prioritization, taking into consideration how much bang for the buck you get and how difficult some of the steps might be to address the issues that we're talking about? You know, some things are no brainers and it's not that hard to deal with the issue. It's easy to implement and you get big bang for the buck. Some are sort of just the opposite. How do we factor all that in, both as market operators and as regulators, in terms of this particular issue--factoring cycling costs into dispatch?

*Respondent 1:* As I mentioned, we view this as part of an ongoing review process that we perform at MISO, so this is a subset of the larger price performance and price formation issue. From our perspective, we've been working on this as an issue since we started operating markets in 2005. There have been many examples where we've made improvements, trying to improve price formation and improve settlement rules and allocation rules in order to create the right incentives to incent the behaviors we're looking for.

How long does it take? It can take a long time sometimes. The white paper that kicked off our ELMP discussion was published in 2009, and there were many years, four or five years of stakeholder discussions and research and

development that led to implementation of our phase one in 2015. So that's an example of what we still think is a very good idea, that took a lot of time to develop and put in place. It's worth the effort if you can find ways to make incremental improvements in price formation to better reflect what market participants, what the market operator, and what economists would agree is an improvement on achieving reflection of true marginal pricing, but that's worth the effort. So we see it as just a continuous process of improvement.

*Respondent 2:* From a generator owner perspective, this isn't going to be the thing that keeps him alive in the future. Say you have more renewables. Lower marginal price generation knocks out these generators out of the stack, but I also would say that CAISO compensates everybody's costs, MISO compensates generators for these costs, and for those ISOs that don't compensate the generators for these costs, is it that difficult of a change to make in those markets to do that?

**Question 2:** Speaker 1, you indicated during your presentation that you believed that the reforms that are being considered in California are unlikely to provide the missing money. And then I looked at your table 13 on page 10, where you show low RA capacity prices and you also present the operating costs. Do you think changes to the RA solicitation and procurement process are part of the solution? And whether you do or not, what fixes do you believe are going to be necessary to avoid a reliability problem?

*Respondent 1:* That's a very good question. I didn't mean to come across as negatively as you characterized. I think compensation is low now, but I see some positive potential reforms that could lift compensation. I did indicate some skepticism that changes to energy and ancillary

services markets, such as contingency modeling enhancements and flexiramp, are likely to be a complete solution. I think something will have to happen on the capacity side as well.

With respect to RA, there are some changes, sort of changes to the fundamentals of the RA market, that might be helpful. So we do have 10,000 megawatts of steam generation hopefully going away. We have maybe the retirement of Diablo Canyon. We're finally going to start counting renewables correctly towards resource adequacy requirements. That could tighten the market. Maybe flexible RA could be redefined in a way that actually results in some scarcity and the procurement of resources that are genuinely operationally flexible.

In terms of a process change, the California market is currently a year ahead forward RA requirement. Given that there's so much uncertainty about the evolving resource mix, it might be helpful to provide a little bit more forward certainty to suppliers. The large investor owned utilities already do a significant amount of forward procurement of resource adequacy, even though the formal requirement is only for a year ahead. So maybe a formal multiyear forward requirement would be helpful. That's something that's been teed up in a variety of different contexts over the last few years. I think some of the reluctance about implementing it actually relates to the fact that the flexible RA product is just not very mature, and a number of stakeholders express concern about layering a new forward requirement on top of a flexible RA product that's really not fully baked. So those are some of the changes I see coming that might be helpful.

**Question 3:** So is the takeaway that this cost ought to be included in marginal cost bids, or is this about the need for a change in the algorithm itself, both in terms of a price adder, I guess, as

well as dispatch? In other words, you would dispatch these units in a different way with a price adder, or is it all the above? I'm trying to understand what the take away is.

*Respondent 1:* At least in California, we can reflect cycling costs and wear and tear in the start costs that we give to the CAISO, and then they actually take those into account in their unit commitment and dispatch decisions. So they're considered already.

*Respondent 2:* The same with MISO. A generator is able to offer a variable commit cost component as part of its startup and no load offers, for example. He can include a variable O&M component in his energy price to help try and reflect this wear and tear issue of using their capacity to produce energy. So there are parameters that allow for asset owners to imperfectly represent those costs to the market and have those reflected in the optimization and the pricing as well.

The question around whether you can make a design that specifically recognizes cycling costs...that would look like a generator saying, "If you're going to cycle me for commitment or dispatch, here is the charge that I need to be paid for that." That would be in a dispatch timeframe similar to the construct we put in place for regulation. Regulation providers submit a cycling cost with their offer. Now what we have to do is turn that into an expected average unit level cycling request in the future, and incorporate that in the optimization. Conceptually, you could do that for a ramp router, you could add an element like that for even a load following product, but it gets much more complicated in that timeframe, the load following timeframe or the ramping timeframe.

*Respondent 3:* I'm not sure if you're going to have this in your bids in the hourly market itself,

because that's more a question of market design, and I'm not sure which is the best way to recover these costs--whether it's an actual average production cost on your bid, or whether it's a lump sum payment or something like that--but in general I think something should be done in order for these costs to be recognized, in order for them to be recovered by the combine cycles. So I'm not talking about market design itself. That's for smarter people to come up with. But, especially in Spain, if you're going to increase your bid it might very easily be misconstrued as taking advantage of market power, and then you might get in trouble with the regulators. So, since calculating these costs of wear and tear is a very complicated process, I think that the discussion should be going in that direction, that something should be done, but I'm not sure what the perfect market measure is.

*Respondent 4:* Can I just illuminate a difference that was stated here? So for Respondent 1, talking about California, every time you start, you can recover that start cost, whereas in MISO it sounds like you need to sort of guess how much you're going to be starting, sort of take that cycling cost, sort of bake that into a variable O&M cost, sort of amortize it over how many megawatt hours you're providing and then get it recovered. So it's a different kind of way to recover those costs, and maybe in the California case it's a little bit more accurate in terms of getting your costs recovered.

*Respondent 1:* I don't know the MISO market well, so I'm not sure how different their construct is, but I think there is an important element of the question that we haven't addressed yet. We can provide accurate start costs to our system operator, but then there are multiple ways that we could end up getting compensated through the market for those start costs. So if the clearing prices are high enough, those might be sufficient for us to recover our

start costs, and if the clearing prices are too low, then we'll recover the start costs through a side payment. And for a bunch of market efficiency reasons, it's probably better to have those costs reflected in clearing prices.

**Question 4:** One of the speakers had a couple bullets talking about how feedback to LMP is the result of co-optimization, and that there is LMP suppression by limiting scarcity parameter pricing. I just wanted to understand what that meant a little more. So I was hoping to just have a bit of expansion on those two points so I could understand the inner relationship between flexiramp and price outcomes in the energy markets.

**Respondent 1:** With respect to the second part of your question about limiting scarcity pricing, that's exactly what Speaker 3 was describing in his presentation, where there are these instances, you know, where the market seems to be working very smoothly, and the prices correspond to the marginal cost of some generator, and then, just because of a very short term shortage of ramp, the prices will spike up to many hundreds of dollars per megawatt hour. And as I understand it, the main reason that the CAISO implemented flexiramp was specifically to avoid those kinds of spikes.

So that was your second question, and on the first question, just like ancillary services in many of the organized markets are co-optimized with energy, so is flexiramp.

**Questioner:** Is the feedback directionally sort of consistent or is it just random?

**Respondent 1:** I have to admit that I don't find flexiramp particularly intuitive, so I'm not sure I can even address that question.

**Respondent 2:** When you hold somebody back, you hold them out of merit, so we do have a multi-interval optimization. So our 15 minute market looks like anywhere between four and seven 15 minute intervals. Our five minute dispatch looks basically like 12 five minute intervals. And when we determine a dispatch or determine the unit commitment in those markets, we ensure that they're economical over the entire horizon. So if you hold back ramp capability, that means that in the financially binding interval you're actually holding a resource out of merit, which means the price in that five minute interval has actually increased, but you're holding it back for good reason, because it's more valuable to you in a later interval.

Now, with the constraint implementation we address the uncertainty issue. If the actual advisory interval that you were solving, comes in a little bit different, you can end up with a spurious price spike. However, if you'd held just a little bit of extra ramp capability, then you're able to now dispatch the fleet, and then you are not using economic bids and not using the relaxation perimeters that you need to do to actually get a solution out of the market. So with the product, we're addressing two issues. We're not going to compensate everybody who's ramping. So, if you're providing the forecasted movement between the binding and the advisory interval, you'll be either paid or charged as to whether or not you're consuming ramp capability or the provider of the ramp capability--and everyone's paid for that, or charged for that-- load, wind, solar, conventional generators. We will also procure an incremental amount in both the upward and the downward portions, but rather than procuring it just with a 60 dollar relaxation parameter, we're going to have a demand curve on it, such that we only buy it if the expected value of avoiding that spurious

price spike exceeds the cost of this holding additional megawatts out of merit.

*Respondent 3:* I would just add the reference to feedback LMP goes to the co-optimization design premise that a generator who is selected to provide a particular product or an ancillary product is not disadvantaged economically as a result of providing that service rather than using his capacity to make energy. So I think that's probably the reference to the LMP feedback. Co-optimization ensures that as a generator owner you're at least indifferent to what market product you're cleared to provide per an interval.

*Question 5:* It almost seems like we're overthinking the problem. Speaker 1, I loved your presentation kind of setting this up, but it seems to me that there are two problems that you're identifying. One is the fact that there's a potential resource adequacy issue and there's not enough money in the market to make sure that we retain existing resources or attract new resources. The second problem is obviously the ramping problem that we just discussed. So to me it seems like there's a relatively straight forward answer, at least in concept. Have you tried a capacity market?

That would be my first comment on the resource adequacy issue, but the second issue is, we talk about ramping capability. It kind of sounds like spinning reserves to me. And so if we think that we're going to run into these serious extreme ramping events, why don't we just hold more reserves? At PJM, if we get behind, if we experience an extreme ramping event, we will deploy synchronized reserves, because, from an operator perspective, whether I'm in an extreme ramping event because it's cold or because I've got a drop off in wind, it doesn't matter. It is observationally equivalent to the operator. It's the same as losing a generator, a contingency for

which we hold reserves to begin with. It is observationally equivalent. I need to make up for that somehow, somehow. Why don't we simply hold excess reserves, rather than calling it ramp or flexiramp or whatever? We could hold more 10 minute reserves, more quick start reserves. And that accomplishes a couple of things. One, it accomplishes the fact that in co-optimization the energy market price will be greater, because you're holding back more potential capability and reserves. And then you're going to have the reserve capability in place in case we have to use it.

Now, I know in WECC they view things differently than we do here in the Eastern Interconnection, but it's something that I throw out there. We have the tools, and we've been using those tools for years. Why are we overthinking that? So that's a question. Why not just do that in California or even in MISO?

The other issue with respect to wear and tear has to do with something Speaker 2 said that I'm going to take issue with here, which is that PJM does not allow those costs to be reflected or recovered. I'm going to disagree with that strenuously. First of all, in market based offers generators can include any of those costs if they so desire. In the cost based offers it's probably not that big a deal in the overall grand scheme of things. And even if they were mitigated, and you are correct that these wear and tear costs are not allowed in the cost based offers, they can, in fact, be reflected in the capacity market as additional costs that are incurred in coming up with the avoidable cost of unit operation over the course of the year. So it can in fact be reflected, but it's not reflected in the energy market. And so my question then is to both you and to Speaker 4. Does it matter where we include it, whether it's in the energy offer or if there's a resource adequacy construct in the

capacity or resource adequacy offer? Does it matter, as long as it can be reflected somewhere?

And then, finally, and this is a question out of ignorance, Speaker 3. With extended LMP, do we have a really good proof of individual rationality for the prices that pop out in extended LMP? We can play around with a lot of toy examples and show that that's indeed true...what I mean by individual rationality is the point where all the market participants are exactly happy at those prices that are being posted--the ELMP prices that are being posted as opposed to posting LMP plus the uplift prices. that we know are efficient as Dick O'Neil And so it's curious, if we can really show that with minimum uplift pricing, those prices are indeed individually rational, then that's great. But do we have that?

*Respondent 1:* OK. On the question about why not just increase your spinning reserves, the answer to that is complicated and technical. And it has to do with the fact that at least in MISO, the available real ramping capability on the system is actually shared among energy and spin and even non spin. So what that means is that if you are in a contingency situation where you need to deploy reserves, you can actually be short of available ramp during that deployment, because MISO is not procuring and enforcing sufficient ramp to simultaneously meet contingent reserved deployment and interval level load following ramp requirement. Why is that important? It's expensive to hold enough ramp to do both, and to do both means you're holding enough ramp to meet your load following requirement plus a contingent deployment of contingency reserves. In MISO the deployment of contingency reserves event happens less than once per month. The system is large enough, like PJM is, that any single unit loss is generally made up for through the automatic dispatch within five or 10 minutes.

There's no need to deploy reserves. So that deployment is a very rare event, and to maintain sufficient ramp on the system for that less than once a month deployment is very expensive. So it's actually more economic to have a dispatch level ramp procurement that you enforce to support the ramp requirements of the dispatch alone, as opposed to the suggestion of carrying more spinning reserve. Reserves are expensive. They're there every interval. So that's the conclusion we came to as we analyzed the cost benefit of those separate approaches.

Which is better? LMP plus uplift or ELMP? LMP plus uplift is a fine economic answer. The problem is that market participants don't see their uplift, at least from MISO, until at least four days after the fact, or seven days after the fact, in the first settlement statements. There's kind of a pre-settlement I think at four days. So that's the question. ELMP brings some of that information up much closer to the operating timeframe. It's within minutes of the actual dispatch. So, which is more economically efficient? It depends on what timeframe you're looking at, but as we've engaged our stakeholders they see virtue and benefit in bringing as much of that uplift impact information into the operating timeframe calculated within minutes of the actual dispatch.

*Respondent 2:* So, with respect to your comment about PJM allowing flexibility costs to be recovered, the utility that I had spoken to who was having trouble in the SPP and the PJM markets was basically doing what Speaker 3 had mentioned, which was he was taking the cycling costs and basically folding that into his variable O&M cost and then getting recovery for that and was not able to do that in PJM or SPP. And so what you're saying is that he could get recovery instead through the capacity or energy markets. They could adjust their bids to help cover for

that cycling piece in another market, hope they clear, and increase those other bids.

And I guess, as a researcher looking at this, it would seem to me that the best approach actually would be something like what CAISO does, which is to actually just be compensated for your startup wear and tear cost directly. Then you don't need to guess, like, am I going to get started 10 times this month or 20 times this month and try and bake that into some other cost and try and hope that you're going to clear the market by adding this extra adder onto some other piece of the service that you're providing that's not really directly related to starts. So I think that that, from a research perspective, would be the best way to go about compensating it, but your point is, you know, that they need to be compensated, and yes, I agree. They need to be compensated somehow. I just think there are better ways to do it perhaps.

*Respondent 3:* My comments are very much in line with what Respondent 2 is saying. Wear and tear costs are due to variable operations. So if they're due to the way that you're operating your plants, then why can't you put them in your actual bid? So from a researcher point of view, that for me would seem something intuitive to do, but then I'm not a regulator and I don't do policies. So if you're not allowed to do that because you have a cost based market, then you're not allowed to actually incur your cycling costs, which also might be difficult to actually calculate. Then what would happen in the future if you have a lot of renewable penetration? I would conjecture that in Spain then all of these combined cycles would not actually be offering in the spot market. They would have to go somewhere else, that might be the reserves market, as you mentioned. So I don't know which is the best way of doing it, but it would seem intuitive to put it into your variable bids.

*Moderator:* And then to the broader question of are we overthinking this and can all this kind of come out in the wash and the capacity markets and in products that we already have...

*Respondent 4:* I think the questioner asked about why California doesn't have a capacity market, and it does. It's just not a very good one. We have a bilateral resource adequacy market, and load serving entities are required to buy capacity to meet the planning reserve margin and buy capacity in certain load pockets. And there are some problems with this bilateral market. One has to do with the way resources are counted. So, for example, we way over count renewables. And that's part of the reason there's a surplus and part of the reason the prices are low. And so hopefully we're in the process of fixing that. Even counting the renewables correctly, there's probably over supply now, but it looks like the load and resource balance is tightening. But there's a lot of uncertainty about exactly how much it's tightening and by when.

So it would certainly be helpful to have a forward mechanism like PJM that sort of rationalizes retirements and provides a little bit more forward certainty, and then it would also be helpful with oversupply to have a demand curve, so that given the current surplus we wouldn't just procure to the planning reserve margin. Maybe we'd procure a little bit extra when capacity is cheap. And that would help keep some of the supply that will be needed in the future more economically viable. But California has a capacity market.

You also had a question about flexiramp, and why we don't just procure more ancillary services. At least in California, it's kind of fundamentally different for most ancillary services in that it can actually be used up. I mean the capacity is unloaded, it's kept unloaded for five minutes, but then after that five minute

interval it can be converted to energy. And typically we don't convert spin and non-spin to energy unless there's a contingency. So it's kind of fundamentally different.

*Question 6:* So with all due respect to my friend who asked Question 5, I don't think we're over thinking this, and in fact I thought this was very helpful, at least in clarifying my own thinking about it, and I want to offer an answer to Question 3 and see if the panel agrees with my view of what it is that's different and what we have to do here.

So, first off, I'm never going to use the word "cycling" again, because I think it has too many ideas embedded in it, and actually it doesn't describe what's going on. And so what we heard here, particularly from the graphs that Speaker 4 showed, is that you have these different operating modes, and different flavors of startup costs. Speaker 2 showed these numbers about cold start and warm start to hot start and the temperature change that's going on and that's going to have a big impact on stress and so forth, but that's very different from going up and down and up and down when you were already operating. Because that isn't much of a delta T, and that's the kind of the analogy to regulation mileage that we're talking about there, which is a different kind of a problem.

And then the ramping issue is a different issue. As Speaker 4 said, that's not what she was talking about, that's something else. So that's a different category, and we want to keep all of those things separate.

And then I come away with the good news, from my perspective...the principle that I think we want to follow, and which at least here in the United States we do follow, which is to try as much as we can make the dispatch actually reflect the physics, and then price to be consistent with the dispatch, as opposed to

saying, "Well, we're going to have hourly prices, and then how do we dispatch around hourly prices?" or something like that. So we want to get it as close as we can get, and I think we're pretty close.

And everybody's familiar with the idea that we're going to have startup costs and then multipart bids. That's not a big innovation. Now, if we have a market power problem, that's an issue we know how to deal with. So you can put in startup costs, and you could have cold start, warm start, and hot start. That wouldn't be very hard. That would be a very modest change, and we could do that, and I think that turns out to be important, because that's where most of the money is, as it turns out. The regulation part we can deal with in the way that they're talking about in California--looking ahead, keeping stuff aside, and pricing it all accordingly, with co-optimization. So that all seems terrific. So we're doing very well with that.

The one thing that strikes me as problematic but unimportant is the mileage for the dispatch part of the story. It may be unimportant, I don't know, but we know how to deal with it conceptually. It's very similar to this problem we have with regulation, where you have a signal, and you're going up and down around the signal, so you're not shutting the plant off. It's running hot, and you're just going up and down, and that incurs some cost, and in principle we would like to deal with that. But what I took away from the numbers here was that that's a relatively small number. So it's not going to be that big a deal. But the advantage of all the other things is that the way costs enter and the way you get remunerated actually matches the physics, which is what you want. So you don't want it in a capacity market. [LAUGHTER] You want it in the startup costs, if it's a startup cost, and if you want it in the ramping cost, if it's a ramping cost. You want it in the energy cost, if

it's an energy cost. There's a component that goes into the energy cost. All those kinds of things are real.

Including the mileage component would be, I think, a fundamental change in the design of current dispatch. This would be a big deal. They don't do it now. The compromise that Speaker 3 was talking about might be the way to incorporate that kind of thing, but I don't think, at least to my knowledge, none of these dispatch algorithms have got a component on the objective function which is the change and the output from one minute to the next minute, and adding in incremental costs to it, separate from the energy cost. For regulation, yes, but not for load following and the other kinds of things that go on here. So that would be the one thing that I learned this morning that might not be structurally in the market design.

Now, the actual implementation, getting the right numbers in and all that kind of stuff, is the usual problem, but I don't consider that to be a design problem. That's just making sure we do our job. But incorporating "mileage" would be the one thing that's a structural change. It seems like most the other issues we discussed today, the structures already there to deal with that. And so that's what I took away as the answer to Question 3 for this panel.

*Moderator:* Great. Any reaction from the panel? All right. Very good.

**Question 7.** On the flexiramp, I think one of the respondents was saying it helped alleviate price spikes. So how is flexiramp recovered? Does it go into LMP, or is it an uplift, or how's that recovered?

*Respondent 1:* So, again, we would co-optimize the flexible ramping requirement with the energy requirement. So in that sense it's

reflected in the energy price. For the forecasted movement between two intervals, there's always a buyer and a seller. And so we will match up who is consuming ramp with those that are providing ramp. But those that are consuming that ramp capability pay for it, and those that are providing it receive compensation for it.

For the incremental portion you buy to address the uncertainty in that advisory interval, because it's not going to be exactly what you thought it was when you ran the market run five minutes ago or 30 minutes ago, for that we do have an uplift, and we do allocate that over a monthly period. It's more of an insurance policy that you're procuring, and since we buy it where the expected benefit of avoiding that spurious price spike is greater than the cost, you basically ensure that the benefits will outweigh the costs of buying that additional megawatt to avoid that spurious price spike, and so the cost allocation is really in essence giving that insurance cost to those that need to buy the insurance, and we look at it over a month, so that those that have more forecast there pick up a larger portion of the cost, because they need more insurance than the one resource that only deviates once.

**Question 8:** Thank you so much. This is really a fabulous panel. I'm wondering, from a societal perspective or from a firm perspective, when do I decide to go and fight and want to change market rules and get compensation? And when do I decide to invest? Also, when we talk about the ramping products and the value of this, how does this shift regionally? I know that our wind resource is, in the upper Midwest, very different, in terms of when it's available, than resources in California, and I'm just wondering if maybe, Speaker 2, you have some ideas of regional differences and how these variable resources could take effect. And then, finally, if you're thinking about larger system issues and we're also factoring demand response into this,

demand response being able to dial down, but also dial up, what types of demand response products would you be developing to help to minimize the wear and tear on these other plants as well? So thank you very much.

*Respondent 1:* Let's see. So, regionally, yes, there is a big difference, because in California they're dealing with all the solar and the duck curve that everyone's sick of seeing, and, you know, in Minnesota it's mostly wind. I think solar brings its own very specific challenges. We used to say, "Solar is just the new wind," and we thought that all the stuff we knew about wind integration would just transfer over to solar. And I no longer think that's true at all. I think solar brings very different challenges. With wind, a lot of the challenges are around predicting when you're going to have a big down ramp and need to bring other resources online. With solar you've got that very definitive duck curve problem, which is a very specific kind of problem, and as you saw, it's like you've got to bring the stuff down and then back up every day. So you can't just de-commit it. You have got to bring it back up every day, and so that brings its own really strong ramping needs, which is why this flexiramp thing is so important for California. So I think the regional differences are real, and they'll be driven by the different resources that the different regions choose to develop.

And I think, in addition, that what you were saying about demand response is extremely important, because with solar...we had done this study for the Large Scale Solar Association where we had looked at some cost effective mitigation options to integrate large amounts of solar in places like California. And because storage is still expensive, what are the things you can do? And demand response--as much load participation in the market as you can get--would be extremely helpful. Being able to get at

least time of use pricing, and moving to real time pricing so that load can actually move around, take advantage of the negative prices in the middle of the day and maybe shift around from the evening peak, would be wholly useful. So if you're thinking about having large amounts of solar, especially, you need to really seriously think about all the different ways in which you can get load to participate in that.

*Respondent 2:* You asked about regional differences in thinking about some of these products and cost drivers. I just wanted to make the point that it's not only regional. So MISO, for example, has a different reality and ramping requirement than California, given the resource mix. But in addition to the regional differences, you've also got real differences driven by fuel prices. So in the MISO region, when the gas price is \$7.00, I'm committing through the day ahead market, primarily. And nuclear is online, and you're committing coal. Now, those resource types typically don't come with a lot of ramp, so the value of ramp and the dispatch interval is higher. So the ramp product may tend to bring on units that are higher cost at \$7.00 gas, just to supply that ramp. At \$2.00 gas, which we've had in recent months, I'm naturally getting a lot of flexible gas units online, just to meet the commit requirement. So the value of ramp at \$2.00 gas is actually probably going to be much less. It's probably going to bind a lot less of the time. So, in addition to region to region variation, just point in time differences in the same region are important too.

*Respondent 3:* Just a quick comment about your question about when is it time to actually make this decision about whether to address something through market design or through technology. From the company point of view, from the utility point of view, the time to make the decision is when the rules are clear, right? Because generation companies are not going to

say, “We’re going to upgrade our equipment,” if they are not sure that they are going to get remunerated for this, right?

And on demand response, I think you’re completely right. I think demand response could help a lot in terms of ameliorating these issues. But then if you’re willing to pay for demand response, why wouldn’t you be willing to pay for what the thermal generators are providing also, right?

**Question 9:** With reference to Speaker 4’s research, what is transition cost and what is deviation cost?

**Respondent 1:** The transition cost factors in the startup and shutdown cost, but it also has a part that is due to the fatigue, the thermal stress, the wear and tear that you incur upon starting up and shutting down. And with respect to deviation cost, let’s say you’re at power one, you’re not committed, you don’t have any power that you produced. And at power two you need to produce 300 megawatts. Then you cannot do that, right? You cannot do that physically, be at zero at one hour and be at 300 megawatts in the next hour, because you actually need to start these machines, warm them up, and so on and so forth. And you have your trajectories. So this deviation cost is really a mathematical concept to have a robust model for you to actually allow for the fact that your exact production does not exactly match the output, since you don’t want these companies to not produce anything at all in terms of mathematical modeling, if you have to penalize them being off of their actual dispatched output. So this deviation cost is this type of concept which could come from an intraday market, for example. A price of a deviating market cost, or in this particular example we’ve actually gone to the very conservative extreme of saying, “We’re going to incur the cost of non-supplied energy.” And so

it’s an interesting result. We’ve seen that actually sometimes in terms of power plant operations, the combined cycle plant would prefer to pay the cost of non-supplied energy than to actually produce what they’ve been dispatched to do. So that’s the deviation cost.

**Question 10:** The person who asked Question 6 said most of what I wanted to say, but I’d just like to add a few things to it. You want to assign cost to the actions that cause them. And if you have, for example, a maintenance contract that says that you have to do maintenance every X number of starts, it’s very easy to figure out how much a start costs you in terms of maintenance cost. You just divide your maintenance contract by X and you get the number you put in, and add that into the startup cost.

The ramping cost seems to me to be the problem for which it is really hard to estimate exactly what the cost is. I mean, maybe you have numbers for it, but that seems to be another difficult problem. So, theoretically, you want to put costs on ramping, but you’re not really sure exactly what they are. You maybe have some statistical studies from other generators, and things of that nature, but that seems to be the tough part, and to me the debate has been around, you know, do we know what these costs are? I mean, philosophically we want to include these costs. But it’s a tough thing to estimate. But I think that’s where we want it, and with all due respect to the person who asked Question 5, building a unit and creating capacity doesn’t cause maintenance cost. So that’s not part of the cost of capacity.

**Response from the person who asked Question 5:** I agree with that. All I was simply pointing out is that there is an avenue within PJM in which those costs can be reflected. I’m not necessarily saying that’s the best place for it.

*Respondent 1:* So the questioner will allow them in the capacity cost, but he won't allow them in the startup costs, where they should be?

*Respondent 2:* My gut instinct is to say that, because he can't measure it, he probably would not allow it in the cost based offer for the energy market, which is why I made the statement that it is possible to include this in a market based offer, and if all of the resources have market based rate authority, then they can reflect it there, since the amount of mitigation is really quite low. You know, it's about, like I said one tenth, maybe two tenths of one percent of all unit run hours. It's not as big a problem as it's made out to be. But in a cost based market, like say in Spain or Argentina, that becomes a bigger issue.

**Question 11:** From listening to the panelists earlier, it sounds like a lot of the issues of the new operational expectations on the gas combined cycle is because these units that were put in in the 90's and the 2000's were put in with the expectation they'd be the new baseload, and that was the way they were designed. And I guess my question is, are there ways we can retrofit the units to give them more flexibility and or call on different types of gas combined cycle to be built now, and if so, for extra credit, how do we send the market signal to do that? Thank you.

*Respondent 1:* I tried to address the first part of your question in my presentation. You're correct that a lot of the existing fleet of combined cycle plants were built for a very different purpose. They were expected to run a lot more, and they weren't designed for flexibility. But there are a lot of really low cost things that can be done to them to make them much more flexible and we've done a fair amount of engineering work on exactly what those things are.

How to get paid for those things? That's much more complicated, especially in California, but one way might be if in the flexible capacity market, the product definition were tightened so that it was actually scarce and flexible or traded at a premium above just plain vanilla RA. As you're aware, the state is very involved in all kinds of procurement activities, so one thing that might happen is in sort of this pseudo IRP process that our public utility commission runs. They might define a need for some incremental flexibility on the system and tell the investor owned utilities to go out and have a solicitation, and that would yield some sort of multiyear contract for these flexibility upgrades.

*Respondent 2:* We've actually been doing some internal studies looking at combined cycles in California and looking at retrofitting them and looking at the cost and benefits of providing more flexibility from those units. And, again, the results are similar to what I mentioned earlier. In that generic study that we did, it really depends on the individual unit as to whether it makes sense. But there are definitely a lot of upgrades that can be done for a reasonable cost, as Respondent 1 was saying.

And I think you're right. There is a whole generation of plants that were sort of procured with this idea that they weren't going to be cycling a lot. And in that case study that I showed, those guys were saying their coal plants could provide all the flexibility and their gas plants couldn't. So there is that, but I think we have a lot of options now that can be taken, and in a lot of these cases in California for the plants we've been looking at, it makes economic sense to do so. Whether you can pay for it is a whole nuther question, and how you get compensated and all of that I don't know so much about.

*Respondent 3:* I'll just add that this idea of a base load unit being forced into a cycling mode is not a new phenomenon. When I started in the

industry in the 1980's at a coal fired power plant, we had 1950's vintage coal units that when they were built were base load units. When I showed up they were cycling units. They shut down multiple times a week. They were ramped up and down. So, yes, there are investments that you can make, changes you can make to those resources to make them capable of operating in that new mode. How those decisions are made and how they're paid for is, again, not a new question. It depends on what environment you're in, and the market based versus traditionally regulated difference comes into play there as well.